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Graduate College

2014

Quantifying the economic competitiveness of cellulosic biofuel pathways under uncertainty and regional sensitivity

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Quantifying the economic competitiveness of cellulosic biofuel pathways under uncertainty and regional sensitivity

by

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A dissertation submitted to the graduate faculty

in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

Major: Biorenewable Resources and Technology

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Ames, Iowa

2014

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACKNOWLEDGEMENTS

I would like to thank my Ph.D. advisor, Dr. Mark Mba-Wright, for providing intellectual and financial support to my research during my time as a Ph.D. student. My graduate school experience has been very unconventional and I am grateful to him for enabling me to pursue course development and teaching activities despite the frequent distractions that they have provided from my research. I would have been unable to reach this point in my career without his constant guidance in everything from implementing new research methodologies to the peer review process to surviving job interviews in academia. I would also like to thank my committee members, Drs. Jacqulyn Baughman, Guiping Hu, Lulu Rodriguez, and Amy Erica Smith both for agreeing to serve on a committee consisting of a wide diversity of disciplines and for providing my research with direction and meaning throughout my studies.

I would like to thank Jill Euken for providing me with numerous speaking and outreach opportunities during my time at Iowa State University. I would like to thank all of the staff at the Bioeconomy Institute for patiently guiding me through the paperwork that is required of direct admit students in interdisciplinary programs. I would also like to thank all of the students who have enrolled in BRT/POL S 515 and 516 over the years for demonstrating to me just how fulfilling of an experience teaching can be.

Finally, I would like to thank my parents and family for providing me with encouragement, advice, and welcome distractions, both before and during my time at Iowa State. I am above all grateful to my wife, Kate, for being an unflagging source of motivation, optimism, and inspiration throughout this experience while simultaneously maintaining her own strenuous academic schedule. I am truly fortunate.

ABSTRACT

The revised Renewable Fuel Standard requires the annual blending of 16 billion gallons of cellulosic biofuel by 2022 from zero gallons in 2009. The necessary capacity investments have been underwhelming to date, however, and little is known about the likely composition of the future cellulosic biofuel industry as a result. This dissertation develops a framework for identifying and analyzing the industry's likely future composition while also providing a possible explanation for why investment in cellulosic biofuels capacity has been low to date.

The results of this dissertation indicate that few cellulosic biofuel pathways will be economically competitive with petroleum on an unsubsidized basis. Of five cellulosic biofuel pathways considered under 20-year price forecasts with volatility, only two achieve positive mean 20-year net present value (NPV) probabilities. Furthermore, recent exploitation of U.S. shale gas reserves and the subsequent fall in U.S. natural gas prices have negatively impacted the economic competitiveness of all but two of the cellulosic biofuel pathways considered; only two of the five pathways achieve substantially higher 20-year NPVs under a post-shale gas economic scenario relative to a pre-shale gas scenario.

The economic competitiveness of cellulosic biofuel pathways with petroleum is reduced further when considered under price uncertainty in combination with realistic financial assumptions. This dissertation calculates pathway-specific costs of capital for five cellulosic biofuel pathway scenarios. The analysis finds that the large majority of the scenarios incur costs of capital that are substantially higher than those commonly assumed in the literature. Employment of these costs of capital in a comparative TEA greatly reduces the

mean 20-year NPVs for each pathway while increasing their 10-year probabilities of default to above 80% for all five scenarios.

Finally, this dissertation quantifies the economic competitiveness of six cellulosic biofuel pathways being commercialized in eight different U.S. states under price uncertainty, utilization of pathway-specific costs of capital, and region-specific economic factors. 10-year probabilities of default in excess of 60% are calculated for all eight location scenarios considered, with default probabilities in excess of 98% calculated for seven of the eight. Negative mean 20-year NPVs are calculated for seven of the eight location scenarios.

CHAPTER 1. INTRODUCTION

1.1.   Background

In 2005 the U.S. Congress passed the Energy Policy Act of 2005, which created a

national volumetric mandate for the blending of biofuel with conventional fuels. The

mandate, named the Renewable Fuel Standard (RFS1), required escalating volumes of

biofuel (see Figure 1.1), which at the time consisted almost entirely of corn ethanol, to be

blended with gasoline prior to retail. Actual production exceeded the mandated volume by

23% in the first year of the RFS1, however, due in large part to the simultaneous but separate

provision of a large refundable tax credit to corn ethanol producers in the form of the

Volumetric Ethanol Excise Tax Credit (VEETC), commonly known as the "blender's credit."
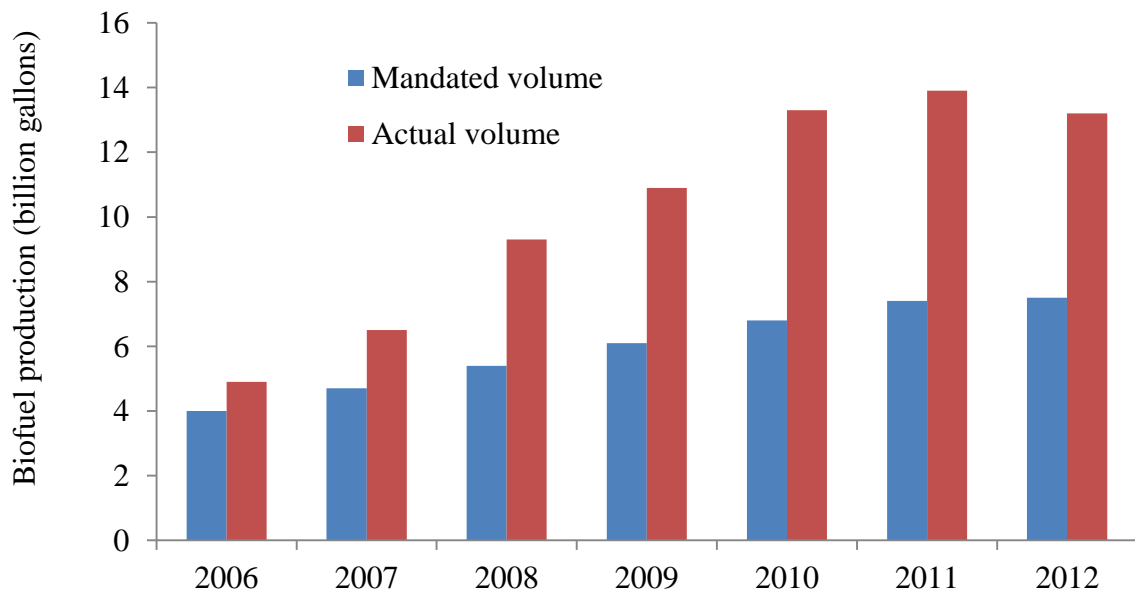
Figure 1.1. RFS1 blending mandates versus actual production (1,2).

In late 2007 Congress passed the Energy Independence and Security Act of 2007. Among other things, the new legislation replaced the RFS1 with an expanded mandate known as the revised Renewable Fuel Standard (RFS2). The RFS2 is significantly larger than the RFS1 in terms of both its overall volumes and its complexity. The total biofuel blending volumes under the RFS2 between 2008 and 2012 are as much as 90% higher than for the same years under the RFS1, reflecting the ease with which the corn ethanol industry exceeded the latter's volumetric mandates (see Figure 1.2).
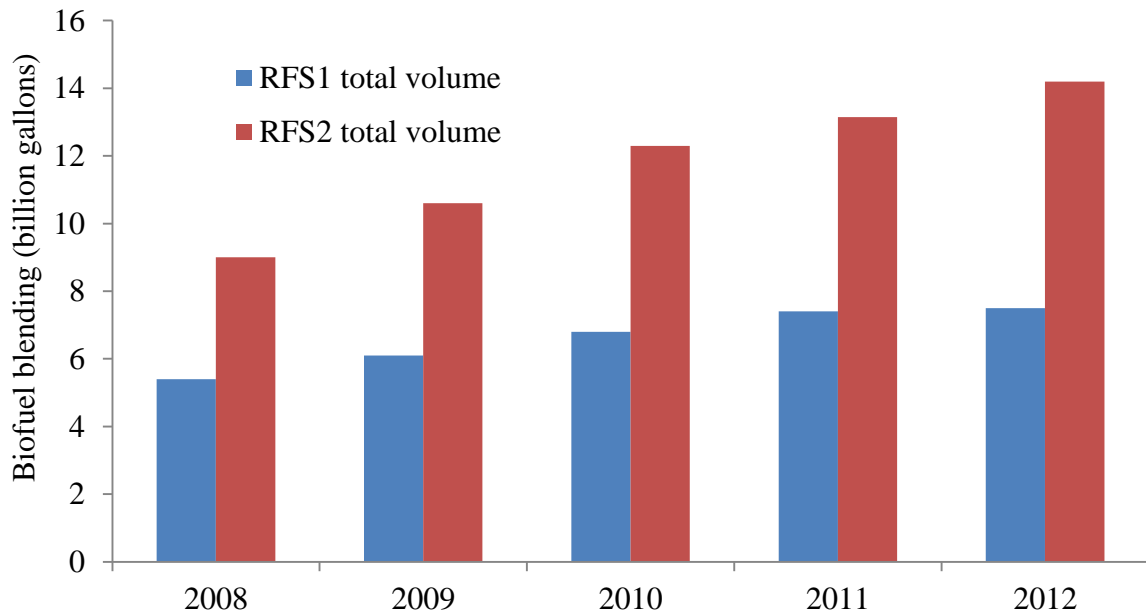
Figure 1.2. Total blending volumes under the RFS1 and RFS2, 2008-2012 (2).

The RFS2 also replaces the RFS1's single biofuel category with four categories, three of which encompass next-generation biofuel pathways. Furthermore, each biofuel category is strictly defined according to both feedstock and lifecycle greenhouse gas (GHG) emissions relative to conventional fuels (see Table 1.1). Finally, the various categories are each nested within the next-largest category, allowing a biofuel meeting the definition of a nested

category to also meet the definition of the larger category in which the nested category is located. The primary category, named "Total Renewable Fuels", encompasses all of the other categories and includes any biofuel produced from biomass feedstock that achieves a 20% GHG emissions reduction threshold relative to conventional fuel. This category's volumetric mandate grows from 9 billion gallons in 2008 to 36 billion gallons in 2022. Corn ethanol's contribution to the total renewable fuels category, regardless of its GHG emissions reduction threshold, is capped at 15 billion gallons per year from 2015 on due to prevailing concerns at the time of the mandate's creation that the use of corn-based biofuels in the U.S. drives chronic hunger (3) and rainforest destruction (4) in the developing world.

Table 1.1. RFS2 biofuel categories and definitions (2).

Mandate category	Feedstock	GHG reduction threshold
Total renewable fuels	Biomass (inc. corn starch)	20%
Advanced biofuels	Biomass (exc. corn starch)	50%
Biomass-based diesel	Non-lignocellulosic biomass (exc. corn starch)	50%
Cellulosic biofuels	Lignocellulosic biomass	60%

Residing within the total renewable fuels category is the "Advanced Biofuels" category. This second category encompasses all biofuels derived from biomass sources other than corn starch that achieve a 50% GHG emissions reduction threshold relative to conventional fuels. While the category's volume is non-existent in the first year of the RFS2, it increases to 21 billion gallons by 2022 (see Figure 1.3), making it larger after 2019 than the maximum corn starch-derived volume permitted by the mandate.
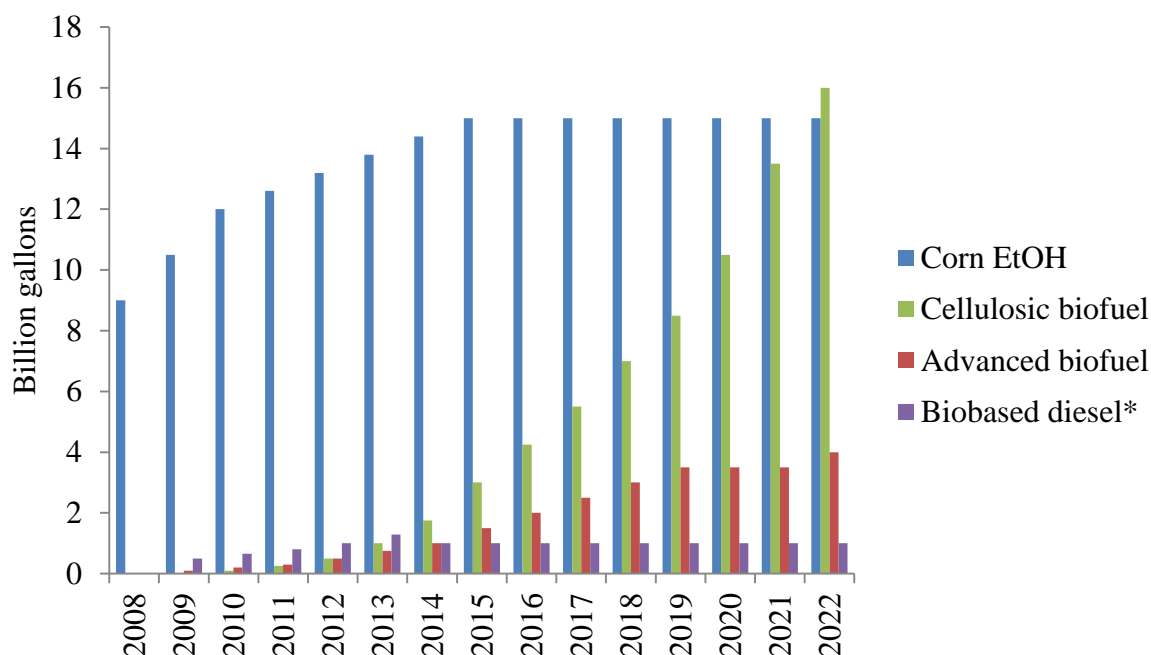
Figure 1.3. Annual volumetric mandates for each category under the RFS2 (2). *The biomass-based diesel category is set annually by the EPA, but the volume is not to fall below 1 billion gallons.

The advanced biofuels category encompasses the final two categories, which are the "Biomass-Based Diesel" and "Cellulosic Biofuels" categories. The biomass-based diesel category covers diesel and diesel-like biofuels (e.g., both renewable diesel and FAME biodiesel) that are derived from non-lignocellulosic biomass and achieve a 50% GHG emissions reduction. In 2013 approximately 86% of the total biofuels blended under the category took the form of lipid-based biodiesel (5). Biofuels under the cellulosic biofuels category are those that are derived from lignocellulosic feedstock and achieve a 60% GHG emissions reduction relative to conventional fuels. The blending mandate for this last category did not commence until 2010 under the original legislation due to the lack of any qualifying production at the time of its passage, which was not the case for the other categories (corn ethanol, cane ethanol, and soybean biodiesel, which qualify for the total

renewable fuels, advanced biofuels, and biomass-based diesel categories, respectively, have long histories of commercial-scale production) (6,7). However, the cellulosic biofuels category is to become the largest individual category by 2022 with a blending mandate of 16 billion gallons, surpassing even the cap on corn ethanol (see Figure 1.3).

The replacement of the RFS1's broad definition of a biofuel with the RFS2's strict, environment-based definitions denoted an important shift in the primary motivation underlying the mandate. Whereas the RFS1 was explicitly created as a means of improving U.S. energy security by replacing imported petroleum with domestic fuel ethanol (8), the inclusion of GHG emissions reduction thresholds in the RFS2's definitions of biofuels shifted the emphasis to environmental security. Congress placed the burden of fulfilling this motivation on the cellulosic biofuels category by defining it according to the strictest GHG emissions reduction threshold and making it the single largest category by volume of the four categories. The ultimate ability of the RFS2 to accomplish its environmental purpose will depend on the cellulosic biofuels industry's successful commercialization from no production in 2010 to 16 billion gallons of production twelve years later. By comparison, the U.S. corn ethanol industry required three decades of commercialization to achieve its first 14 billion gallons of production (1).

The RFS2 employs two mechanisms to ensure compliance with the blending mandate. The first mechanism is the imposition of a binding blending requirement on refiners and other parties supplying conventional fuels to the retail market, termed "obligated blenders" by the program. Obligated blenders are required to blend a percentage of the overall RFS2 mandate in a given year that is determined by their share of the U.S. refining market; those failing to blend the required amount face a fine of up to $32,500 per violation

(i.e., per gallon) per day (2), ensuring that non-compliance is an economically-irrational behavior. A tradable compliance commodity known as Renewable Identification Numbers (RIN) is used to demonstrate compliance on the part of obligated blenders to the Environmental Protection Agency (EPA), which is tasked with implementing the RFS2. A RIN is created when a gallon of biofuel is produced or imported and contains information on the type of biofuel, when it was produced or imported, where it was produced or imported, etc. The RIN remains attached to the biofuel until it is blended with conventional fuel for retail, at which it is separated by the blender. Each obligated blender must submit a sufficient number of RINs to the EPA by the end of each year to demonstrate that it has fulfilled its share of the annual blending mandate.

RINs also operate as a mechanism to ensure that biofuel is either produced or imported in sufficient quantities to permit compliance with the blending mandate. As tradable compliance commodities RINs can be sold from one party to another much in the manner that carbon credits are traded in cap-and-trade schemes. For example, an obligated blender that possesses more RINs than it needs to demonstrate full compliance in a given year can sell the excess to an obligated blender holding insufficient RINs. The ability of RINs to be traded ensures that those for each category have a unique market price, creating a monetary incentive for the generation of separated RINs in addition to the aforementioned non-compliance fine via biofuel blending. Furthermore, since RINs are only created via the production or importation of biofuel, at least some of each RIN's value can be expected to be passed on to the biofuel producer, incentivizing the biofuel's production as well as its blending with conventional fuels for retail. Due to the trading mechanism RINs provide enough of a subsidy to biofuel producers and non-obligated blenders to ensure that sufficient

biofuel is produced and blended with conventional fuels to make compliance with the RFS2 possible but without creating windfall profits (9). RINs increase in value when the costs of biofuel production and/or blending rise and vice versa, falling to zero when blending exceeds the volumetric mandate since no RIN value is necessary at that point to ensure compliance with the mandate. Because RIN values are determined via a market-based mechanism, however, they can only be known for those biofuel categories in which biofuel is being both produced and blended with conventional fuels for retail.

Finally, the value of a RIN depends on the type of biofuel produced (as distinct from the RFS2 category that it qualifies for). RINs are attributed on an ethanol-equivalent basis for the four RFS2 categories. The different types of biofuels that have been blended with conventional fuel as part of the RFS2 mandate include ethanol, FAME biodiesel, gasoline, and diesel fuel (5). The energy content of each biofuel type is different (10) and FAME biodiesel, gasoline, and diesel fuel receive more than one RIN per gallon as a result (see Table 1.2), making them more valuable than ethanol in terms of RIN value per gallon. The relationship between RIN value and biofuel type is limited to the aforementioned RFS2 categories and the biofuel's energy content, however; so long as a biofuel achieves the 60% GHG emissions reduction threshold of the cellulosic biofuel category then there is no additional value to be attained by achieving a still-higher reduction threshold (assuming that cellulosic biofuel RINs have a greater value than those of the other categories).

Table 1.2. RINs created per type of biofuel (5)

Type of biofuel	Number of RINs created per gallon
Ethanol	1.0
Biogas	1.0
Heating oil	1.1 – 1.6
Butanol	1.3

Table 1.2 continued	
Type of biofuel	Number of RINs created per gallon
FAME biodiesel	1.5
Gasoline (naptha)	1.5
Diesel fuel	1.5 – 1.7

The total renewable fuels, "other" advanced biofuels (the share not attributable to the biomass-based diesel and cellulosic biofuels categories), and biomass-based diesel volumetric mandates have largely been met to date (11,12) and even exceeded in the case of the latter (5). Production of cellulosic biofuels, on the other hand, has fallen far short of the category's volumetric mandates since the RFS2's inception due to a lack of capacity investment. Recognizing that insufficient global capacity has been available to meet the mandate, the EPA has adjusted the cellulosic biofuels volumetric mandates down by as much as 99% in every year since 2010 (see Figure 1.4). Actual production of cellulosic biofuels still fell short of the EPA's adjusted volumes by at least 94% and as much as 100% for each of those years.
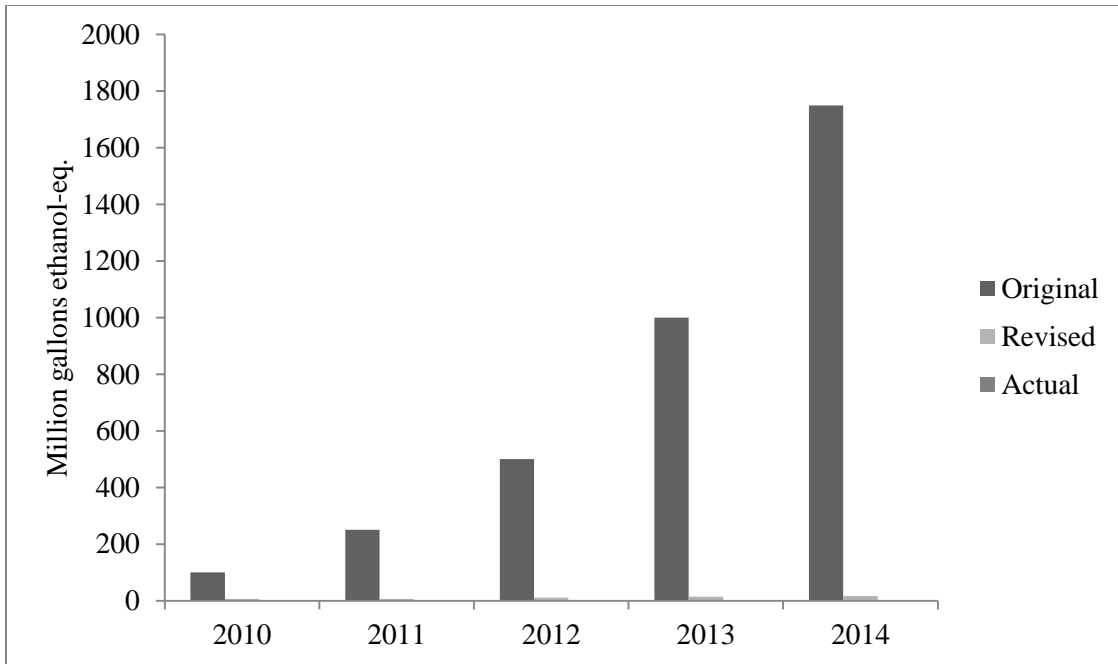
Figure 1.4. EPA adjustments to the cellulosic biofuels volumetric mandates, 2010-2014 (2). Actual volume for 2014 is not known at time of writing. Actual volumes for 2012 and 2013 were 0.02 million and 0.82 million gallons, respectively.

The lack of cellulosic biofuel production to date has created an implementation dilemma for the EPA and raised uncertainty regarding the category's future viability. In calculating the adjusted cellulosic biofuels volumetric mandates the EPA has intentionally erred towards overestimates in an effort to support investment in the industry (13,14). This practice has been employed since a biofuel category's RIN values approach zero when blending exceeds the volumetric mandate. Were the EPA to release an adjusted volumetric mandate that is ultimately surpassed by blending then cellulosic biofuel RINs would fall in value despite the original volumetric mandate not being met, inhibiting continued capacity investment. By setting the adjusted volumes too high, however, the EPA has placed obligated blenders in the position of being legally required to blend non-existent biofuels with conventional fuels for retail. In January 2013 the U.S. Court of Appeals for the District of Columbia overturned the cellulosic biofuels mandate due to the EPA's practice of

overestimating the adjusted volumes, although it limited the scope of its ruling to the volumetric mandate in 2013 (14).

Notwithstanding the EPA's efforts, the complete lack of cellulosic biofuel production in 2010 and 2011 and virtual lack of production in 2012 have prevented the market from identifying a cellulosic biofuels RIN price due to a lack of RIN supply. This has prevented cellulosic biofuels RINs from successfully fulfilling one of their primary purposes, which is to incentivize capacity investment by providing producers and blenders with a subsidy for ensuring that the biofuel is made available for blending and retail. Investment has been inhibited by the lack of a clear subsidy for cellulosic biofuel production, in turn ensuring that the subsidy continues to be missing in the future due to a lack of investment and subsequent production. Biofuels qualifying for the other three RFS2 categories were already being produced and/or imported at the time that the respective volumetric mandates were implemented, allowing for the value of each category's RINs to be quickly known. This discrepancy between the categories will only grow more pronounced as the cellulosic biofuels volumetric mandate continues to increase rapidly on an annual basis, with the 3 billion gallons mark to be reached in 2015.

The future viability of the broader RFS2 also became more uncertain in 2013 due to technical issues involving the blending and consumption (as opposed to production) of fuel ethanol. Unlike hydrocarbon-based fuels, ethanol is miscible with water and any water contaminating a pipeline, storage tank, or pump (e.g., via condensation) is absorbed by ethanol as it passes through (10). In addition to causing corrosion in unmodified equipment, blending ethanol that has absorbed water with gasoline results in phase-separation that interferes with proper engine operations. U.S. ethanol blends with gasoline in unmodified

vehicles have largely been limited to 10 vol% ("E10") because of this miscibility; while the EPA began permitting blends of up to 15 vol% ("E15") in 2010 (15), its acceptance by consumers has been minimal and limited to the Midwest (16). Adoption rates of flex-fuel vehicles, which can consume ethanol blends of up to 85 vol% ("E85"), have also been too low in the U.S. to cause a significant increase in ethanol consumption (17). Ethanol consumption in the U.S. is roughly limited to 10 vol% of gasoline consumption with the current fuel infrastructure as a result.

The RFS2 was created at a time when U.S. gasoline consumption was forecast to steadily increase over the next two decades (18). Long-term gasoline consumption is now forecast to slowly decline over the same period due to changing driving habits, the slow economic recovery in the aftermath of the 2008 Financial Crisis, and significant improvements in vehicle fuel economy (19). In 2013 the U.S. hit the ethanol "blend wall", which is defined as the point at which ethanol consumption equals 10 vol% of gasoline consumption, when ethanol production continued to increase even as gasoline consumption fell. The arrival of the blend wall has created multiple problems for the RFS2. The first is over the ability of U.S. refiners to blend and consumers to utilize the volumes of ethanol required by the mandate. In 2017 only 13 billion gallons of ethanol will be permitted by the blend wall according to current forecasts (19), which is below the 15 billion gallons of corn ethanol permitted by the mandate, let alone any additional volumes of ethanol in the form of advanced and cellulosic biofuels. The type of biofuel produced in the future within the cellulosic biofuels category is now an important question with regard to the category's future feasibility. If the biofuels produced under the category primarily take the form of ethanol, as was originally anticipated by Congress, then corn, cane, and cellulosic ethanol will be forced

to compete for a share of a shrinking ethanol market (see Figure 1.5). Hydrocarbon-based

biofuels (and butanol to a lesser extent) are not limited by the ethanol blend wall due to their

chemical similarity to petroleum-derived fuels, however, so cellulosic biofuels taking those

forms will not face the same future constraints as cellulosic ethanol.
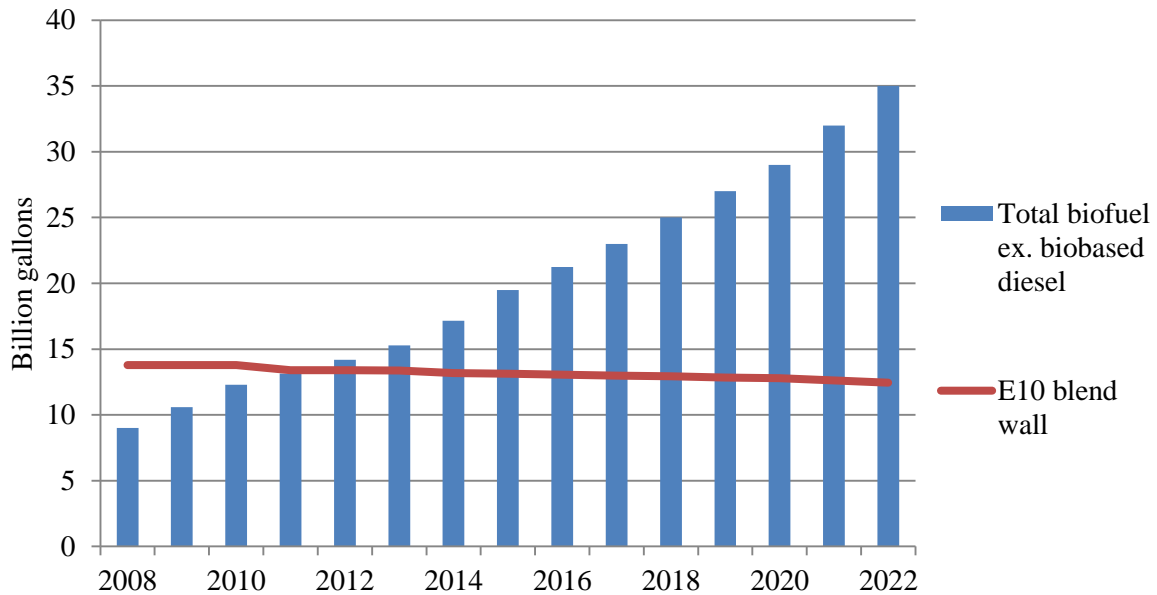
Figure 1.5. The E10 blend wall relative to the RFS2 volumes that do not exclude fuel ethanol
(2,19).

The arrival of the blend wall in 2013 also increased uncertainty regarding the future

viability of the RFS2 by causing RIN prices, particularly for the total renewable fuel

category, to increase by 2800% between January and July of that year. RIN prices for the

total renewable fuels (D6) category had barely exceeded transaction costs from 2010 to the

end of 2012 due to the ease with which the corn ethanol industry produced sufficient biofuel

for its share of the blending mandate to be met (20). Never exceeding $0.04 during that

period, D6 RIN prices were too low to incentivize blending by many obligated blenders as

they found it easier to purchase the RINs necessary to demonstrate their compliance on the

market. The lack of volatility in the RIN markets changed in early 2013 following the broad

realization that the volumetric mandates for the year exceeded the ethanol blending volumes

permitted by a 10 vol% blend wall. Faced with insufficient blending capacity and consumers

unwilling to purchase higher ethanol blends, obligated blenders were required to continue

purchasing RINs even as their prices rapidly increased (see Figure 1.6). Large financial

institutions reportedly increased the volatility by purchasing large volumes of RINs at low

prices in anticipation of the blend wall and then waiting to sell them to obligated blenders

until after they had greatly increased in value (21). One large obligated blender, Valero,

reported over the summer that it expected its total RIN costs for the year to increase to $800

million due to the rising prices.
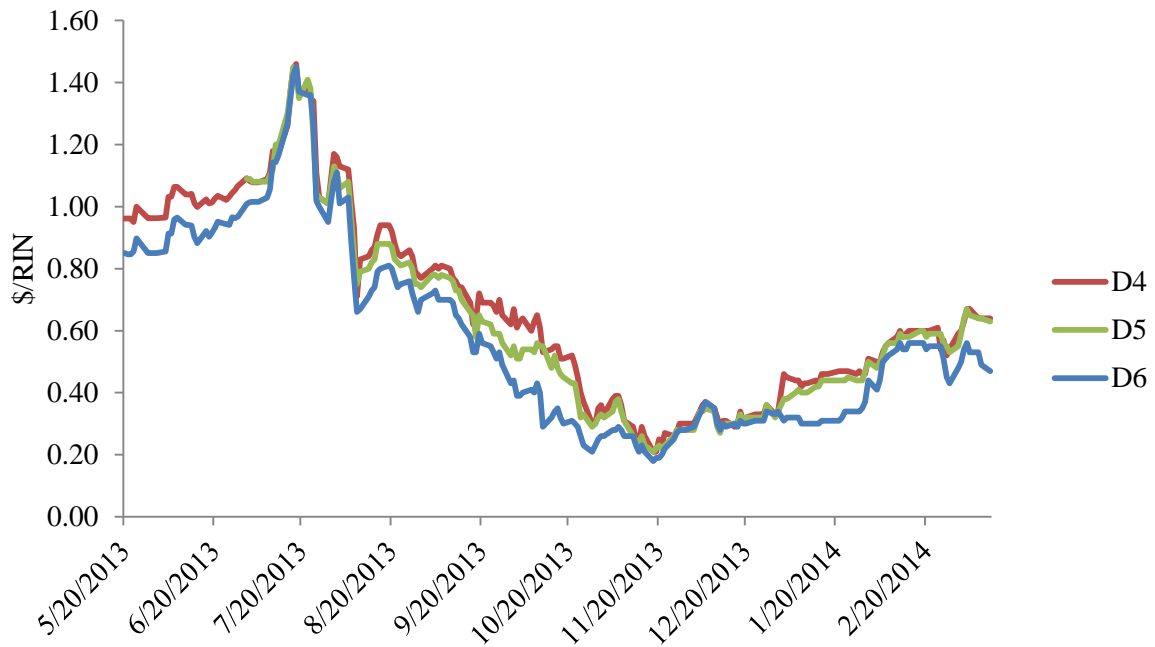
Figure 1.6. RIN prices since May 2013 (22). D4 = Biomass-based diesel category; D5 = Advanced biofuel category; D6 = Total renewable fuel category.

The refining industry launched a large lobbying effort in Washington D.C. during the

second half of 2013 to convince Congress and the EPA to reform or even repeal the RFS2 as

a means of reducing RIN prices. In August the EPA responded to this effort by promising to

consider the constraints imposed by the ethanol blend wall in determining the volumetric

mandates for 2014 (23), causing RIN prices to begin falling in value (see Figure 1.6). In

November the EPA formally proposed to adjust the volumetric mandates for the total

renewable fuels and advanced biofuels categories, much as it has done to the cellulosic

biofuels category, so that the combined volume of both does not exceed 10 vol% of U.S.

gasoline consumption (Table 1.3). While the EPA has yet to release its final rulemaking on

the 2014 volumetric mandates, such a reduction would establish the precedent of reducing

the total blending requirement for the two categories each year for the foreseeable future (see

Figure 1.5). Any cellulosic biofuels production taking the form of ethanol would presumably

be constrained in a similar manner, forcing it to compete with corn ethanol and cane ethanol

for both RINs (since the EPA would determine the annual allocation) and market share.

Cellulosic hydrocarbon-based biofuels face no such limitation, however, and future

production of this biofuel type would not be limited even in the event that the EPA

formalizes the blend wall constraints within the RFS2's volumetric mandates.

Table 1.3. 2014 volumetric mandates for the RFS2, both original and proposed (24).

Category	Original 2014 volumes (billion gallons)	Proposed 2014 volumes (billion gallons)
Total renewable fuels	18.15	15.21
Corn ethanol cap	14.40	13.01
Advanced biofuels	3.75	2.20
Biomass-based diesel[a]	1.28	1.28
Cellulosic biofuels	1.75	0.02
"Other" advanced biofuels	0.72	0.26

[a]All volumes except biomass-based diesel are presented on an ethanol-equivalent basis; each gallon of biomass-based diesel is equivalent to 1.5 gallons of ethanol.

Forecasting the future viability and results of the RFS2 under the ethanol blend wall requires knowledge on the feedstocks and pathways likely to be employed and resulting biofuel types. Cellulosic ethanol's production costs are significantly higher than those of both corn ethanol and cane ethanol due to high feedstock costs and the recalcitrant nature of lignocellulose (6). Cellulosic ethanol is uncompetitive with other ethanol pathways (let alone petroleum) on an unsubsidized basis as a result. The future viability of the cellulosic biofuels mandate under a scenario in which cellulosic ethanol is the category's primary fuel type would require RINs to subsidize its production, blending, and consumption at a sufficient level to make it competitive with these other products (25). The lack of a blend wall for cellulosic hydrocarbon-based biofuels reduces the level of subsidization necessary under a scenario in which they are the cellulosic biofuels category's primary fuel type since only production would need to be incentivized, although this would also be determined by the production costs of the respective pathways.

Knowledge of these three factors (feedstocks, pathways, and biofuel type) is also important if the impacts, both positive and negative, of the cellulosic biofuels mandate are to be determined. Cellulosic biofuels differ from corn and cane ethanol in that the latter are almost entirely derived from single feedstocks in specific regions (e.g., the U.S. Midwest, Brazil's Mid-South and Northeast). It has been estimated that cellulosic biofuels production in the U.S. alone will utilize three broad feedstock groups (forest biomass, agricultural residue, and dedicated energy crops) from at least four regions (26). Furthermore, in 2012 no fewer than six different cellulosic biofuel pathways within both the biochemical and thermochemical platforms producing both ethanol and hydrocarbon-based biofuels were expected to achieve commercial-scale production by the beginning of 2015 (27). Techno-

economic analyses (TEA) of these pathways have found that their production costs vary widely even after accounting for differences in assumed feedstock costs and product market prices (28–31). Furthermore, production costs for an individual pathway are determined in part by the location in which it is employed due to regional differences in feedstock type, feedstock cost, capital costs, and market prices (32).

Differences in the ability of each cellulosic biofuel pathway to compete with conventional fuels will also contribute to other impacts of the RFS2's cellulosic biofuels mandate that are not explicitly economic in nature. These impacts can be categorized as environmental, ecological, and socioeconomic. The environmental impact that has received the greatest attention due to the way in which the RFS2 is structured is an individual pathway's reduction to lifecycle GHG emissions relative to conventional fuels. While several of the pathways currently undergoing commercialization have been determined to achieve a 60% GHG emissions reduction threshold (33–38), the actual emissions reduction varies by pathway and feedstock. Hsu et al. (39) identifies differences in feedstock yields, nitrogen fertilizer application rates, removal rates, and moisture contents between different lignocellulosic feedstocks as being the most influential parameters in terms of lifecycle GHG emissions for a single cellulosic biofuels pathway. Hsu (35) calculates a 65% reduction to GHG emissions for the fast pyrolysis and hydroprocessing pathway and a 90% reduction for the gasification and mixed alcohols synthesis pathway, both of which yield cellulosic biofuels. Zhang et al. (34) reports that the 65% reduction for the fast pyrolysis and hydroprocessing pathway can be increased to an 88% reduction by utilizing biomass-based hydrogen rather than natural gas-based, although Wright et al. (28) calculates that this increases the pathway's production costs by as much as 50%. Tao et al. (40) calculates that

biofuel type also affects the lifecycle emissions reduction of a cellulosic biofuels pathway, with ethanol produced via dilute-acid pretreatment and enzymatic hydrolysis generating a 69% reduction versus a 63% reduction for isobutanol produced via the same route.

The EPA (41,42) calculates an emissions reduction range of 65-129% for the cellulosic biofuel pathways that it has approved under the RFS2 to date, indicating that some pathways are carbon negative (i.e., they achieve a net reduction to atmospheric GHGs) when the appropriate product portfolio is generated. In some cases a trade-off is identified between GHG emissions reductions and biofuel yields (34,43). The type of land on which the lignocellulosic feedstock is produced is also an important factor: Searchinger et al. (4) reports a 50% increase to lifecycle GHG emissions for cellulosic ethanol relative to conventional fuels when switchgrass feedstock is grown on productive cropland in the U.S. Midwest, while Gelfand et al. (44) reports large emissions reductions when the feedstock is instead grown on marginal cropland in the same region.

The ecological impacts of cellulosic biofuels are primarily associated with direct land-use change. Positive ecological impacts can result from the growth of certain types of lignocellulosic biomass on marginal lands; for example returning marginal cropland in the Midwest to its original state via reforestation or conversion to switchgrass production. Baker et al. (45) and Elobeid et al. (46) both calculate that the reforestation or afforestation of productive cropland would cause U.S. food production to fall and increase the prices of crops such as corn, soybeans, and wheat by as much as 39%, however, making the type of land on which lignocellulosic feedstock production occurs an important factor. Wildlife in production areas can also be impacted by these decisions, as some species prefer habitats consisting of long post-harvest stubble while others prefer short stubble (47). In the case of corn stover,

high harvest rates contribute to soil erosion from water and wind as well as soil carbon depletion (48). Corn stover yields are closely correlated to grain yields (49) and increased future demand for stover feedstock could result in higher rates of fertilizer application in an effort to boost both. Finally, future demand for stover could also induce farmers to switch from corn-soybean rotations to continuous corn crops (50), much as occurred in the U.S. during the first decade of the 21st century, potentially causing greater losses of nitrogen and phosphorous to water (51).

Finally, cellulosic biofuel production can be expected to have socioeconomic impacts within the U.S. Whereas the costs of the RFS2 are borne by conventional fuel consumers via the refiners that are required to either purchase or generate separated RINs, the immediate beneficiaries of the mandate have yet to be identified. Many U.S. lignocellulosic feedstocks are only grown in certain regions (26), making the choice of both feedstock and pathway important determinants of the regions in which feedstock and biofuel production under the RFS2 will ultimately occur. Studies report mixed socioeconomic impacts from existing bioenergy projects including regional revitalization (52), concentration of wealth in large-scale producers resulting in the social exclusion of small producers (53), and shifting attitudes toward bioenergy adoption (54). A better understanding of the type and magnitude that these impacts are likely to have under the RFS2 requires further knowledge on the cellulosic biofuel feedstocks and pathways that are most likely to contribute to the mandate.

1.2.   Dissertation Objectives

The primary objective of this dissertation is to develop a methodology for comparative techno-economic and uncertainty analyses of cellulosic biofuel pathways. This primary objective is completed via three specific objectives:

1. Quantify the economic competitiveness via techno-economic analysis of eight cellulosic biofuel pathway scenarios within two energy commodity price scenarios under price volatility.

2. Develop a framework for quantifying the economic competitiveness of cellulosic biofuel pathways by incorporating pathway-specific financial assumptions and energy commodity price uncertainty into techno-economic analysis.

3. Quantify the economic competitiveness via techno-economic analysis of eight cellulosic biofuel pathway scenarios with pathway-specific financial assumptions, energy commodity price uncertainty, and region-specific location scenarios.

1.3.   Intellectual Merit

This dissertation advances the current methodology employed to quantify the economic competitiveness of cellulosic biofuel pathways by incorporating realistic financial assumptions, price volatility and uncertainty based on the combination of historical price movements and price forecasts, and region-specific factors into a single framework. The results of the studies included in this dissertation provide new information on the short-term competitiveness of the cellulosic biofuel pathways currently being commercialized relative to petroleum and one another. Furthermore, the methodology employed to produce this result has been presented in a manner that can be utilized by researchers with access to Monte

Carlo simulation software, public databases, and the open literature. This methodology can incorporate new data on cellulosic biofuel pathways and commercialization as it becomes available to continuously update the competitiveness assessment and provide additional information on the likely near- and mid-term composition of the cellulosic biofuel industry, permitting research into the future viability and impacts of the industry broadly and the RFS2 specifically.

1.4.   Dissertation Organization

This dissertation is organized as five chapters. Chapter 1 provides a brief history of U.S. biofuels mandates in the 21st century and an overview of the specific mechanisms by which the RFS2 incentivizes sufficient biofuel production to ensure compliance with its blending mandates. Chapter 1 also discusses both the challenges facing the future viability of U.S. cellulosic biofuels and the quantification of the same. Finally, Chapter 1 details the objectives, intellectual merit, and organization of this dissertation.

Chapter 2 addresses this dissertation's first objective, which is to quantify the economic competitiveness of eight cellulosic biofuels pathways within two 20-year energy commodity price scenarios under price volatility. Chapter 2 develops each cellulosic biofuel pathway based on the results of techno-economic analyses in the open literature. The energy commodity price scenarios are derived from government price forecasts from before and after the large-scale U.S. exploitation of shale gas reserves. Price volatility is modeled via a Monte Carlo simulation methodology that derives probability distributions from historical monthly variations around the annual mean prices of five energy commodities. These probability distributions are applied to both energy commodity price scenarios, allowing for

the economic competitiveness of each pathway scenario to be calculated under future price volatility. Chapter 2 has been drafted as a standalone manuscript that has been published in the refereed international journal *Fuel* and includes supporting information.

Chapter 3 addresses the second objective of this dissertation, which is to develop a framework for quantifying the economic competitiveness of cellulosic biofuel pathways. Chapter 3 accomplishes this by incorporating pathway-specific financial assumptions and energy commodity price uncertainty into techno-economic analysis. The pathway-specific financial assumptions are calculated using methodologies from the financial analysis literature, replacing the generic assumptions currently employed by techno-economic analyses of bioenergy pathways. Energy commodity price uncertainty employs Monte Carlo simulation on the basis of each commodity's historical month-on-month price variations and 20-year price forecasts. Chapter 3 has been drafted as a standalone manuscript that has been submitted for publication in the refereed international journal *Biofuels*.

Chapter 4 addresses the third objective of this dissertation, which is to quantify the economic competitiveness of eight cellulosic biofuel pathway scenarios with pathway-specific financial assumptions, energy commodity price uncertainty, and region-specific location scenarios. Chapter 4 expands upon the methodologies introduced in Chapters 2 and 3 by incorporating region-specific factors such as differences in capital costs, feedstock type, feedstock costs, commodity prices, and tax rates. Eight location scenarios representing planned commercial-scale cellulosic biofuel projects in the U.S. are developed and their economic competitiveness with conventional fuels and one another are quantified and compared. Chapter 4 has been drafted as a standalone manuscript for submission to a refereed international journal.

Chapter 5 summarizes the primary conclusions of this dissertation as presented in Chapters 2-4. It also discusses future research directions that would expand upon and utilize the methodologies introduced in the previous chapters.

CHAPTER 2. TECHNO-ECONOMIC IMPACTS OF SHALE GAS ON CELLULOSIC
BIOFUEL PATHWAYS

A paper published in the international refereed journal *Fuel*

Tristan R. Brown[1] and Mark M. Wright[2]

2.1.   Abstract

This analysis quantifies the economic feasibility of cellulosic biofuel pathways under fossil fuel price uncertainty. Eight pathway scenarios are developed on the basis of existing techno-economic analyses and projected fossil fuel commodity prices from the Energy Information Administration's (EIA) 2010 Annual Energy Outlook (AEO). A 20-year net present value (NPV) is then calculated for each pathway scenario. Uncertainty distributions are developed for each pathway scenario by fitting historical monthly price variance distribution curves for each fossil fuel commodity to their projected annual prices. Finally, a sensitivity analysis is completed by replacing the EIA's AEO 2010 projected prices with those from its AEO 2013, the latter incorporating recent exploitation of U.S. shale gas reserves into its projections. The results of this analysis indicate that fast pyrolysis scenarios see the greatest increase in estimated NPV value followed by gasification and acetic acid synthesis scenarios. Fischer-Tropsch synthesis scenarios remain largely unaffected by the updated EIA projections. Methanol-to-gasoline and enzymatic hydrolysis NPVs decrease as a result of lower projections for fossil fuel prices.

Keywords[3]

Cellulosic biofuel; shale gas; techno-economic analysis; uncertainty analysis

2.2.   Introduction

The widespread deployment of technology enabling the inexpensive extraction of

shale gas has caused U.S. natural gas production to increase substantially in recent years,

with annual U.S. production currently at a level never seen before (55). One effect has been

significantly lower U.S. monthly wellhead gas prices, which in April 2012 fell below

$2/MMBTU for the first time in the 21st century (56). This development signifies a

fundamental shift in the dynamic between the prices of petroleum and natural gas.

Natural gas has historically been a byproduct of petroleum extraction, resulting in a

strong correlation between the prices of the two commodities (56,57). Divergences in their

price movements over the last 25 years have been characterized by their brevity and

infrequency, usually corresponding to extreme weather events and rarely lasting for more

than a few months (see Figure 2.1). Starting in 2009, however, this correlation in price

movements began a monotonic divergence. By 2012 the price of WTI petroleum had

increased 200% over the previous decade on a nominal basis, while the wellhead price of

U.S. natural gas on the same basis had fallen to a 13-year low. Meanwhile both U.S. natural

gas production and proved reserves have reached historical highs (58), with the increase in

the latter almost entirely attributed to an increase in proved reserves of shale gas (59).

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petroleum gas; LTG = low-temperature gasification; MMBTU = million British thermal units; MT = metric ton; MTG = methanol to gasoline; NCG = non-condensable gases; NPV = net present value; RFS2 = revised Renewable Fuel Standard; RIN = Renewable Identification Number; SMR = steam methane reforming; TEA = techno-economic analysis; TPEC = total purchased equipment cost; TPI = total project investment; WTI = West Texas Intermediate.
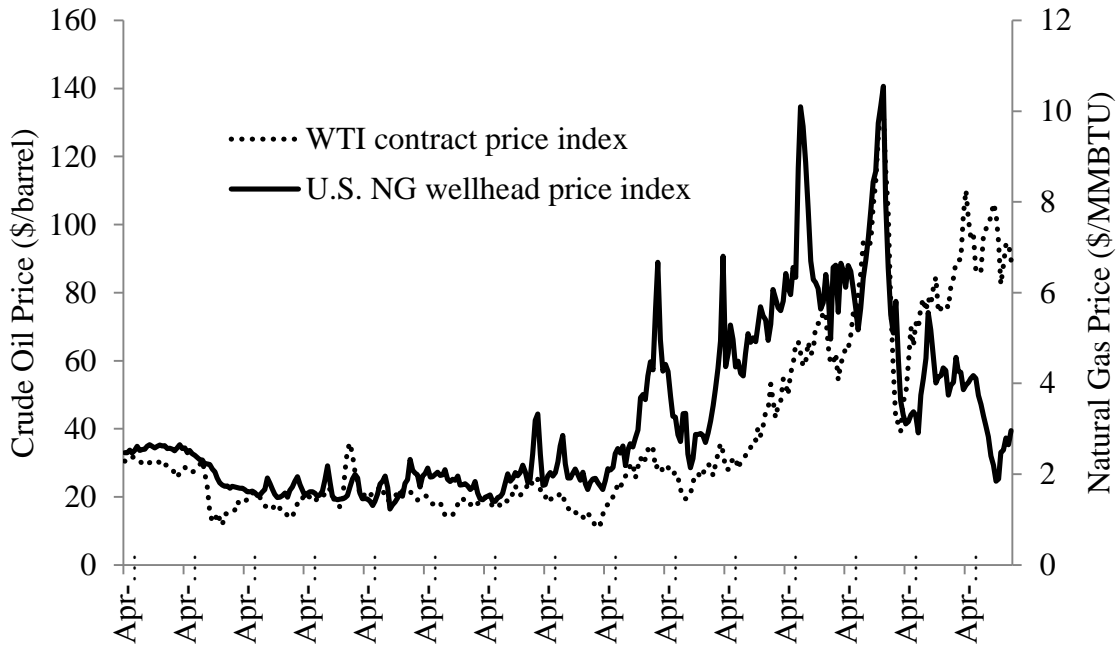
Figure 2.1. Monthly U.S. natural gas wellhead and WTI contract nominal price, 1983-2012 (56,57).

The EIA forecasts this price divergence to be the start of a new multi-decade trend (see Figure 2.2). The U.S. natural gas wellhead price in 2035 is currently projected to be only 58% that of the commodity's trend based on the historical correlation between U.S. natural gas and WTI prices (19). Should these projected prices occur then this new price relationship will represent a complete reversal of the historical relationship.
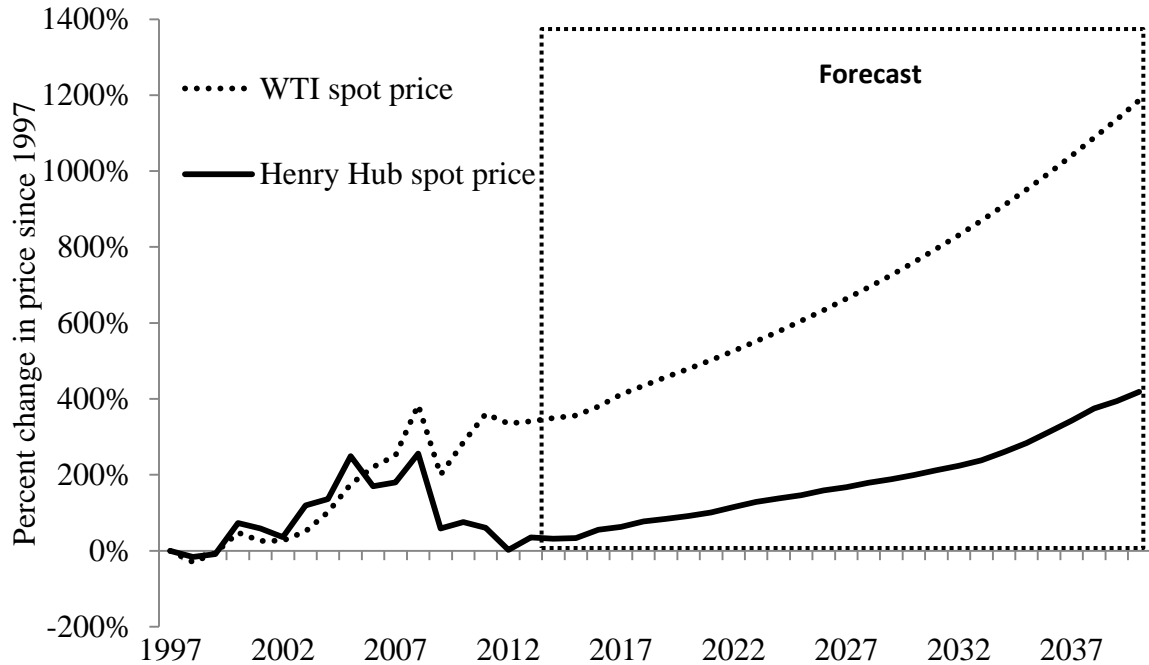
Figure 2.2. Historical (1997-2012) and projected (2013-2040) increases in annual nominal natural gas ($/MMBTU) and West Texas Intermediate (WTI) petroleum ($/bbl) spot prices (19).

The wide gap between projected natural gas and petroleum prices has caused some U.S. policymakers to question the wisdom of investing in high-cost cellulosic biofuels at a time when domestic natural gas is available as an inexpensive feedstock for production of fossil fuel-based synthetic transportation fuels (synfuels). Congressional legislation introduced in 2012 would expand the RFS2 to include both biofuels and synfuels (60). Two would-be cellulosic biofuel producers announced in the same year that they were switching from biomass to natural gas as alternative fuels feedstock in part due to low natural gas prices (61,62). The domestic economics of synfuel pathways are more attractive at present than in the past due to lower input costs (natural gas and coal) and higher output prices (gasoline and diesel fuel). While lifecycle assessments (LCA) of synfuels pathways such as gas-to-liquids (GTL) and coal-to-liquids (CTL) report higher greenhouse gas (GHG) emissions than for

petroleum-based transportation fuel pathways (63–65), the absence of a national carbon tax or price program in the U.S. limits the negative impact that this has on the fuels' economic feasibility.

Largely ignored in the discussion of the impact of shale gas on the economics of alternative transportation fuel production is its potential ability to improve the economic feasibility of biofuel production. U.S. biofuels policy has undergone a major shift over the last decade, greatly expanding its scope to include hydrocarbon-based cellulosic biofuels in addition to cellulosic ethanol (66). Hydrocarbon-based biofuel pathways directly utilize hydrogen in either one- or two-step processes of deoxygenation and depolymerization to increase overall yields of monomeric hydrocarbons. Hydrogen can be derived from a number of sources although the least expensive source with current technology is produced via the SMR of natural gas (67,68). The new relationship between natural gas and petroleum prices can therefore be expected to directly impact the economic feasibility of hydrocarbon-based biofuel pathways.

Based on current facility construction, U.S. cellulosic biofuel production will reach 215 MM gallons gasoline-equivalent in 2014, slightly more than half of which will be hydrocarbon-based (27). These cellulosic biofuel facilities will employ several different pathways, including gasification and FTS; gasification and MTG; and EH and fermentation. This analysis quantifies the impact of U.S. shale gas production on the economic feasibility of these pathways, in addition to fast pyrolysis and hydroprocessing and gasification and AAS. Spreadsheet models were created using pathway data in the techno-economic literature to quantify the economic feasibility of each pathway under two different economic scenarios based on the EIA's price forecasts from its AEO 2010 and AEO 2013. Uncertainty analysis

was employed using historical price variation data in conjunction with the price projections to quantify scenario performance under uncertainty.

2.3. Methodology

This study proceeds as follows: (1) process and economic data of select biofuel pathways were collected and adjusted, (2) historical data on monthly commodity price variation distributions were gathered and fit to probability distributions, (3) a range of NPVs were estimated for each pathway scenario based on stochastic analysis of the commodity prices and economic parameters. Figure S2.1 outlines the steps taken in this study.

Seven different cellulosic biofuel pathways were selected to develop eight pathway scenarios: (1) HTG and FTS; (2) LTG and FTS; (3, 4) stand-alone FPH; (5) DHG and AAS; (6) IHG and AAS; (7) EH and fermentation; and (8) gasification and MTG synthesis. The two gasification and FTS scenarios were developed using data from the high- and low-temperature scenarios presented by Swanson et al. (2010) (29). Two separate TEAs of the FPH pathway were used to develop Scenarios 3 and 4: Brown et al. (2013) (69) and Jones et al. (2009) (70) (referred to here as "BFPH" and "JFPH", respectively). The direct- and indirect-heat gasification scenarios presented by Zhu and Jones (2009) (71) were used to develop the two gasification and AAS scenarios. The EH and fermentation scenario was based on work by Kazi et al. (2010) (72). Finally, the gasification and MTG scenario was developed using the results of Phillips et al. (2011) (73,74). The pathway scenarios are described in more detail in a later section. Table S2.1 summarizes the mass balances and annual operating hour assumptions of the eight pathway scenarios. All of the pathway scenarios are based on original facility capacities of 2000 MT/day, although it should be

noted that optimal facility sizes can differ across pathways (75). The pathway scenarios were chosen based on the availability of detailed techno-economic analysis (TEA) results and this selection is not an exhaustive list. However, the methods in this study can be readily applied to TEAs of emerging pathways as they are published provided they contain the TEA data presented in Table S2.1 and Table S2.2.

While the TEAs used to develop each scenario in this analysis are similar in that the results are presented in formats that are broadly comparable, there are several differences between them (e.g., cost basis year, capital cost calculation methodology, annual operating hours, etc.). First, the assumed feedstock cost is not the same across all pathway scenarios and has been adjusted to $83/MT in 2011 dollars in this analysis. Second, while differences in the cost basis year are adjusted to 2011 dollars using the U.S. city average Consumer Price Index as the cost multiplier (76) (see Table S2.2), the capital cost calculation methodology and annual operating hours remain the same as presented in the cited studies. While these assumptions affect the results of each scenario, it is not immediately clear whether or not they are arbitrary in nature. For example, while the companion technical report to Phillips et al. (74) provides a detailed justification of its capital cost calculation methodology (73), the remaining studies do not. Given the ambiguous nature of the capital cost calculations, then, this analysis does not adjust the capital cost calculation methodologies and annual operating hours of the cited studies to place them all on the same basis. Finally, the capacity factors for each pathway scenario also remain unchanged from the cited studies for the same reason, although this too can be expected to affect pathway economic feasibility (77,78). The results of each pathway TEA are not strictly comparable as a result.

Several different energy commodities are employed as either inputs or outputs by the eight pathway scenarios (see Table 2.1 and Table S2.1). While the TEAs listed in Table S2.1 and Table S2.2 assume static prices for each commodity over the 20 year period analyzed, these prices have historically been subject to substantial price volatility (see Figure S2.2). Assuming that the commodity prices remain volatile in the future, this volatility makes it unlikely that static prices will occur in the future. It is more likely that the future prices will exhibit similar volatility. Rather than calculate a point estimate of pathway economic feasibility as was done in the previously-cited TEAs, then, this analysis employs Monte Carlo simulation to calculate a range of NPVs and probabilities based on price variability for the commodities employed as inputs and outputs.

Table 2.1. Probability distribution function selection and expected value for each commodity price (79).

Commodity	Distribution	2010 Projection (2013-2032 average)	2013 Projection (2013-2032 average)	Historical data years and source
Electricity (industrial)	Triangular	$0.066/kWh	$0.065/kWh	2001-2012 (29)
Diesel fuel	Logistic	$3.18/gal	$3.30/gal	1994-2012 (30)
Gasoline	Logistic	$3.09/gal	$2.95/gal	1993-2012 (30)
LPG	Logistic	$2.02/gal	$1.26/gal	1993-2012 (31)
Natural gas (Henry Hub)	Logistic	$7.73/MMBTU	$4.49/MMBTU	1992-2012 (2)
Hydrogen[a]	Logistic	$1.76/kg	$1.08/kg	-

[a]Calculated as a function of natural gas price (80)

Electricity, diesel fuel, gasoline, hydrogen (produced from natural gas via SMR), LPG, and natural gas were selected for the Monte Carlo simulations due to their use in biorefineries, commercial availability, and the availability of historical monthly price data.

Feedstock, catalysts and process water were excluded despite their use as inputs in most of the pathway scenarios due to a lack of available historical data for the first two and a low impact on pathway economic feasibility for the latter. Feedstock type, ultimate analysis, and moisture content are presented in Table S2.3. Other important sources of pathway cost uncertainty are beyond the scope of this study and discussed elsewhere (81,82).

A variety of methodologies for developing energy commodity price distributions have been employed in the techno-economic literature. The simplest technique represents their uncertainty via triangular distributions based on either a historical price range (83) or a predetermined percentage range (e.g, +/- 30%) around a mean projected price (84–86). While straightforward, Shlyakhter et al. (1994) report that these price distributions are inaccurate when applied to energy markets since they attribute zero probability to outliers (87).

A second technique represents energy commodity price uncertainty via uniform distributions based on the combination of historical price ranges and contemporary market prices, with the former operating around the latter (88,89). This technique attributes equal probabilities to all prices within the range and makes the important assumption that historical price ranges are an accurate predictor of future price ranges. While true for some commodity prices in the past (e.g., WTI petroleum from 1983 to 2003), this assumption is unsuitable for an analysis considering the breakdown of an historical price relationship. Furthermore, this technique also assumes that the future mean price is the same as the contemporary price, which is unsuitable when future commodity market conditions are anticipated to be substantially different than contemporary conditions.

A third technique represents energy commodity price uncertainty via normal distributions based on projected price ranges and projected mean prices (90). While this

allows for anticipated changes in future commodity market conditions to be accounted for, normal distributions around projected prices have also been found to underestimate the frequency of extreme outcomes (although not to the same extent as triangular distributions) (87).

This analysis accounts for price outliers by developing and employing fitted distributions for each input parameter (see Table 2.1). The distributions were developed using the historical monthly price variations of each energy commodity in a given year around the annual average price for the same year. The appropriate distribution for each commodity price was selected based on the results of the Anderson-Darling goodness-of-fit test (91). The monthly price variation distributions are then applied on a monthly basis to the respective annual commodity prices in the DCFROR spreadsheet. This approach generates logistic distributions for all of the historical commodity price variations except electricity, reflecting heavier tails relative to normal distributions. The historical data generates a triangular distribution as the best fit for electricity. An important assumption of this technique is that the historical price variation of each commodity remains the same in the future.

Reference operating costs were also adjusted for each scenario to account for differences in assumed commodity costs. Prices for all major commodities (the averages are presented in Table 2.1) were derived from the annual prices projected for 2013-2032 by the EIA in its AEO 2010 report (79). The prices of gasoline and diesel fuel exclude fuel excise taxes by subtracting the national average excise tax for both (92) from the EIA's projected prices. It is assumed that hydrogen is produced on site via SMR of natural gas. Hydrogen price was calculated using the Department of Energy's (DOE) H2A Central Hydrogen

Production Model (80) as a function of the natural gas price and a 149 MT/day output capacity.

A stochastic DCFROR spreadsheet was used to calculate a 20-year NPV probability distribution for each pathway scenario using the data presented in Table S2.1 and Table S2.2. The stochastic model is based on a deterministic DCFROR model developed by the National Renewable Energy Laboratory and modified by Wright et al. (2010) (93,94). The stochastic model has two important differences from the original deterministic model. First, the stochastic model operates on a monthly rather than annual basis to permit the incorporation of the monthly price variation distributions. Second, the stochastic model incorporates Monte Carlo simulations to develop projected commodity price distributions for each of the commodities presented in Table 2.1 and the 240 months accounted for by the spreadsheet. All NPV calculations assume a 10% IRR, 100% equity financing, and a 35% corporate income tax rate. Of these three assumptions, the NPV calculations are most sensitive to the assumed IRR (77,78). The Monte Carlo simulations were employed to obtain NPV distributions and quantify the certainty that the NPV of each pathway scenario is > $0, based on the above assumptions. The simulations were performed with Crystal Ball® software and were based on 10,000 trials.

The historical price data was analyzed to identify correlations between different commodities. For example, gasoline and diesel fuel are both produced via the refining of petroleum and the prices of both can be expected to be closely correlated as a result. Crystal Ball® software was also used to identify correlations between historical monthly commodity prices via Spearman's correlation coefficient. Very strong correlations, defined here as a correlation coefficient of greater than 0.9, were identified for gasoline and diesel fuel prices

(0.975) and gasoline and LNG prices (0.935). These correlations were incorporated into the appropriate assumptions within the Monte Carlo simulations to prevent ahistorical price divergences between closely-correlated commodities.

Finally, a sensitivity analysis was employed by comparing the eight pathway scenarios under the AEO 2010 energy commodity price projections with those from the AEO 2013. The AEO 2013 scenario employed the same methodology as the AEO 2010 scenario, with price variability distributions derived from historical data applied to the projected prices. The AEO 2013 prices are different from the AEO 2010 prices, however, particularly for natural gas and LPG (see Figure S2.**3**). The sensitivity analysis quantifies the impact that the changing price relationship resulting from increased shale gas production has on the economic feasibility of the eight pathway scenarios analyzed here. A Supporting Information document containing descriptions and schematics (see Figure S2.4) of each of the pathway scenarios considered by this analysis can be found online.

2.4.   Results and Discussion

4.1.1. Uncertainty Analysis Based on 2010 Projections

We compare the effects of electricity, gasoline, diesel fuel, LPG, and natural gas prices on the NPV of eight techno-economic scenarios based on seven cellulosic biofuel pathways. Figure 2.3 presents the NPV probability distributions of the economic scenarios derived from the EIA's AEO 2010/2013. The BFPH, JFPH, and gasification and MTG scenarios are all calculated as having 100% certainty of achieving NPVs of greater than zero (see Figure 2.3). On the other hand, the remaining scenarios all have a zero probability of achieving a positive NPV based on the model assumptions and projected prices.
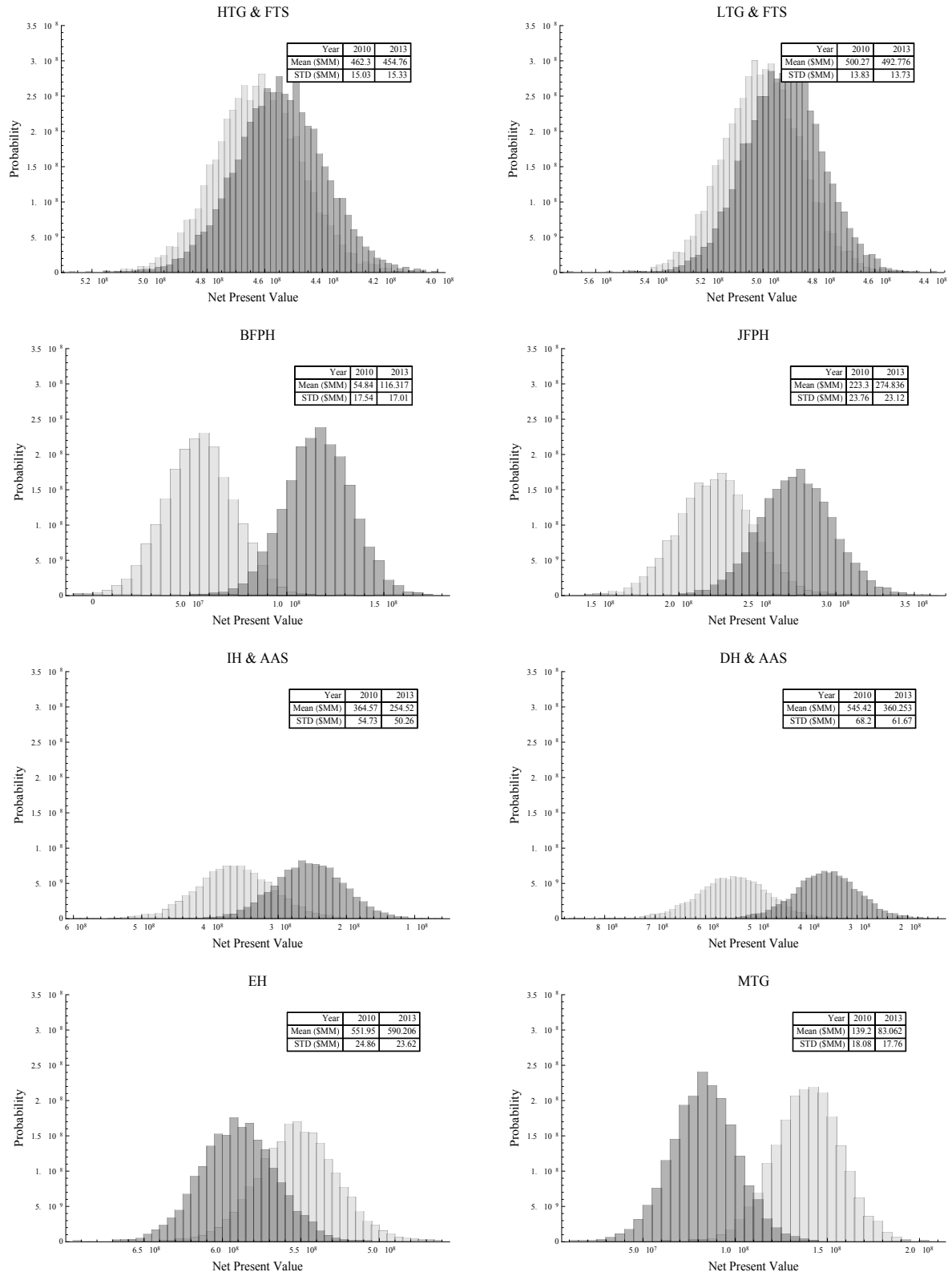
Figure 2.3. NPV comparison of biorefinery scenario uncertainty analysis based on 2010/2013 fuel price projections. Light shading indicates the AEO 2010 scenario and dark shading indicates the AEO 2013 scenario.

The wide range in NPV standard deviations for the various gasification pathways indicates that the fuel synthesis route employed has a noticeable effect on pathway economic feasibility, as these scenarios all convert the biomass feedstock to syngas via a gasification step. The standard deviation of each pathway scenario NPV is also driven by the number of different pathway scenario inputs and their quantities. The IHG & AAS and DHG & AAS scenarios have the largest NPV standard deviations of $54.7 MM and $68.2 MM, respectively. The two pathway scenarios are also the largest net consumers of electricity, hydrogen, and/or natural gas (see Table S2.1). Exposure to multiple fossil fuel inputs results in a broader NPV probability distribution than those pathway scenarios with less exposure, especially when the inputs are not correlated. While this diversity of inputs decreases the sensitivity of NPV to a sharp change in the price of a single input, it also increases NPV uncertainty. However, we note that there are other factors unaccounted for by this analysis that could influence the profitability of these pathway scenarios.

4.1.2. Uncertainty Analysis Based on 2013 Projections

A sensitivity analysis is employed to quantify the effect of changing energy commodity prices on each pathway's NPV under uncertainty. This sensitivity analysis is accomplished by replacing the 20-year energy commodity prices from the EIA's AEO 2010 with those from the AEO 2013 (see Table 2.1) (19). The 20-year average electricity and gasoline prices are slightly lower while that of diesel fuel is slightly increased relative to the AEO 2010. LPG and natural gas prices (and hydrogen by extension) are sharply reduced in the AEO 2013 as a result of the sharp increases in shale gas production and proved reserves that have occurred since the AEO 2010 was released. The Monte Carlo simulations for each

pathway scenario are run in the same manner as described above. The primary difference is that the historical price variation probability distributions operate around the AEO 2013 prices for 2013-2032 rather than the AEO 2010 prices.

The results of the sensitivity analysis show that the effect of the AEO 2013 projected prices on each pathway scenario is largely determined by the level of hydrogen and/or natural gas consumption (see Figure 2.3). The HTG & FTS, LTG & FTS, and EH scenarios experience only marginal changes (<10%) to the mean NPV relative to the same scenarios under the AEO 2010 prices. None of these three scenarios consume external natural gas or hydrogen; furthermore, both FTS scenarios yield both gasoline and diesel fuel, allowing the lower price of the former to at least partially offset the higher price of the latter. Only the EH and MTG scenarios experience lower mean NPVs under the AEO 2013 prices than under the AEO 2010 prices. This reduction is particularly pronounced for the MTG scenario, which neither consumes hydrogen and/or natural gas nor yields a commodity that increases in value under the AEO 2013 relative to the AEO 2010.

All pathway scenarios benefit from higher gasoline and diesel prices, although EH does not benefit as much as the other scenarios due to the lower energy content (and consequent lower market value) of fuel ethanol relative to gasoline and diesel fuel. The impact of electricity prices depends primarily on whether the biorefinery is a net consumer or producer of electric power. Higher electricity prices result in a decrease to NPV for facilities that are net electricity consumers and an increase to NPV for those that are net electricity producers. Electricity production among net producers varies by pathway, ranging from 1 MW for the IHG & AAS scenario to 28.2 MW for the BFPH scenario. Facilities deriving a high proportion of their revenues from electricity see the greatest benefit from projected

increases in electricity prices. Similarly, natural gas prices have the most impact on the economic feasibility of biorefineries that depend heavily on an external supply of natural gas as either their source of hydrogen or heat and power. Natural gas could also impact LPG, which is a co-product of MTG and the market value of which is influenced by natural gas prices.

Two conclusions can be drawn from the results of this analysis. First, when historical energy commodity price variability is accounted for in projected prices over the next 20 years, both the mean and standard deviation for the NPV vary substantially across pathway scenarios. Second, when the effects of U.S. shale gas exploitation are considered in the form of updated EIA price projections (AEO 2013), the BFPH, JFPH, IHG & AAS, and DHG & AAS scenarios experience substantial (>10%) increases to mean NPV, while the MTG scenario experiences a substantial decrease to mean NPV.

These conclusions raise an important possible policy implication with regard to the RFS2. Lower natural gas prices both now and in the future improve the economic feasibility of those pathways that utilize natural gas as a pathway input, either directly or in the form of natural gas-derived hydrogen. While most of the pathways considered by this analysis can use biomass as a source of hydrogen rather than natural gas, such a substitution reduces pathway biofuel yields and decreases its economic feasibility as a result (93). Pathways such as gasification and FTS, FPH, and gasification and AAS therefore have a strong economic incentive to employ as much natural gas as is technically feasible, especially during early years of operation when natural gas prices are projected to be particularly low. While not all of the pathways considered by this analysis experience an increase to economic feasibility under the AEO 2013 price projections relative to those of the AEO 2010, economic

feasibility does benefit from reduced natural gas prices; however, the benefit isn't always sufficient to offset the other price changes in the AEO 2013. The two gasification and FTS pathway scenarios, two gasification and AAS scenarios, and EH scenario all are unable to generate a positive NPV under the AEO 2013 price projections even when natural gas is assumed to have no cost, indicating that they will struggle to be economically feasible as biorenewable pathways.

While reduced natural gas prices increase economic feasibility, the results of this analysis suggest that continued shale gas exploitation alone will be insufficient to make most of the pathways considered here economically feasible. Only two of the pathways considered (gasification and MTG and FPH) are found to have a greater than zero probability of achieving a positive NPV under the AEO 2013 projected prices, and even those probabilities might be too low to acquire the large amounts of capital from investors needed to achieve commercial-scale production. The RFS2 with its variable subsidy in the form of RINs can be expected to contribute to cellulosic biofuel economic feasibility as a result. While this subsidy has been worth nearly $2/gal for other biofuel categories in the past (20), qualifying cellulosic biofuels must achieve a reduction to lifecycle GHG emissions of 60% relative to gasoline (95). As a fossil fuel, natural gas consumption increases pathway lifecycle emissions relative to biomass consumption. Consumption of too much natural gas, therefore, can disqualify a cellulosic biofuel pathway from the RFS2 and result in a net reduction to economic feasibility when RIN values are high. Furthermore, increased natural gas consumption can diminish the economic feasibility of pathways employing it in regions such as the European Union that impose a price on GHG emissions. While the use of natural gas as a hydrogen source doesn't necessarily disqualify pathways such as FPH on the basis of

lifecycle GHG emissions (35), further research is needed to quantify how much natural gas can be used as a pathway input before the pathway reduction to lifecycle GHG emissions falls below the 60% threshold for cellulosic biofuels.

2.5. Conclusion

This paper quantifies the 20-year net present value (NPV) for seven cellulosic biofuel pathways under eight different pathway scenarios using a discounted cash flow rate of return (DCFROR) spreadsheet. Input costs, output yields, and output prices are derived from techno-economic analyses (TEA) in the open literature and the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2010. Uncertainty analyses for each pathway scenario are completed by developing fitted distributions based on historical price variations for diesel fuel, electricity, gasoline, LPG, and natural gas and applying them to the 20-year projected prices for each commodity in the AEO 2010.

The results of the uncertainty analysis show that the mean 20-year NPV and standard deviation calculation for each pathway scenario varies significantly, with the two fast pyrolysis and hydroprocessing (FPH) scenarios and single gasification and methanol-to-gasoline synthesis (MTG) scenario generating NPV probabilities in excess of zero. The lowest mean NPVs are generated by the four gasification scenarios and the single enzymatic hydrolysis (EH) and fermentation scenario. The two gasification and AAS scenarios produce the largest standard deviations of all pathway scenarios considered, indicating a high degree of NPV uncertainty for both.

A sensitivity analysis is also completed by replacing the AEO 2010 energy commodity prices with those from the AEO 2013, the latter accounting for the major increase

in U.S. natural gas production and proved reserves resulting from the recent exploitation of shale gas. This development is reflected in much lower natural gas and LPG prices in the AEO 2013 relative to the AEO 2010. Four of the eight pathway scenarios analyzed (BFPH, JFPH, IHG & AAS, and DHG & AAS) experience substantial increases to mean NPV when the AEO 2013 prices are considered. The gasification and MTG synthesis and EH and fermentation pathways experience decreases to mean NPV under the AEO 2013 prices, although the latter pathway experiences only a marginal decrease to mean NPV.

2.6.   Supporting Materials
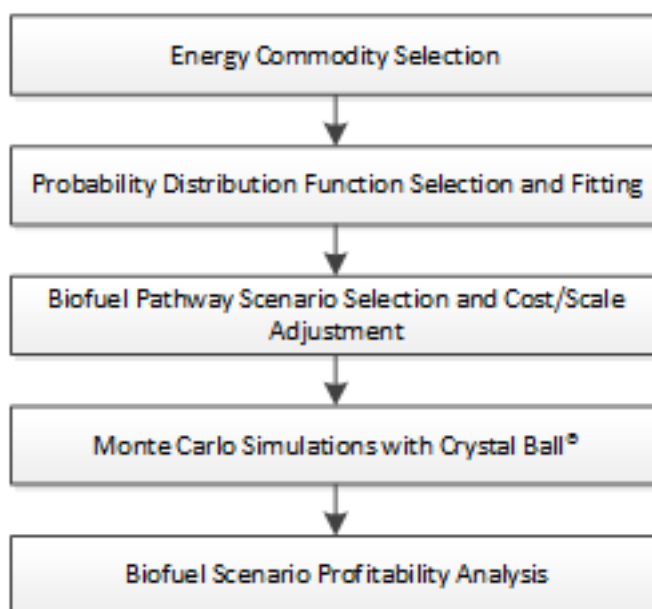
Figure S2.1. Methodology for the profitability analysis of biofuel scenario pathways based on commodity prices

Table S2.1. Process scenario mass balances and annual operating hours. All scenarios assume 2000 metric tons per day (MTPD) of biomass input and $83 per MT feedstock cost. (MGY – million gallons per year).

Scenario	Pathway	Operating hours/yr	Net electricity required (MW)	Natural gas consumption (MT/day)	H_2 consumption (MT/day)	Gasoline output (MGY)	Diesel fuel output (MGY)	Energy efficiency (%)[a]
S1 (29)	HTG & FTS	7446	-13.8	0	0	12.9	25.8	53.2
S2 (29)	LTG & FTS	7446	-16.4	0	0	10	20	42.7
S3 (69)	BFPH	7900	-28.2	0	49.1	28.7	28.7	59.5
S4 (70)	JFPH	7900	7.5	288.4	0	72.2	3.8	55.5
S5 (71)	IHG & AAS	7900	-1	0	123.2	96.7	0	55.4
S6 (71)	DHG & AAS	7900	14.2	155.8	149.4	117.3	0	56.5
S7 (72)	EH	8400	-25.8	0	0	35.6	0	45.3
S8 (74)	MTG	8400	0	0	0	42.5	0	42.6

[a] LHV basis

42

Table S2.2. Capital and operating costs of process scenarios adjusted 2011 US dollar cost basis

Scenario	Pathway	Total project investment (MM$)	Fixed operating cost (MM$/yr)	Co-product credit (MM$/yr)	H_2 cost (MM$/yr)	Other variable cost (MM$/yr)	Natural gas cost (MM$/yr)
S1 (29)	HTG & FTS	657.4	15.5	6.8	0	12.6	0
S2 (29)	LTG (& FTS)	540.3	30.1	8.1	0	13.1	0
S3 (69)	BFPH	429.0	12.4	14.8	32.5	1.8	0
S4 (70)	JFPH	328.7	18.1	0	0	27.2	25.3
S5 (71)	IHG (& AAS)	627.1	36.7	0.5	77.9	88.1	0
S6 (71)	DHG (& AAS)	781.1	44.5	0	92.8	105.6	13.7
S7 (72)	EH	407.9	10.7	15.6	0	67.2	0
S8 (74)	MTG	216.5	15	13.4	0	2.1	0
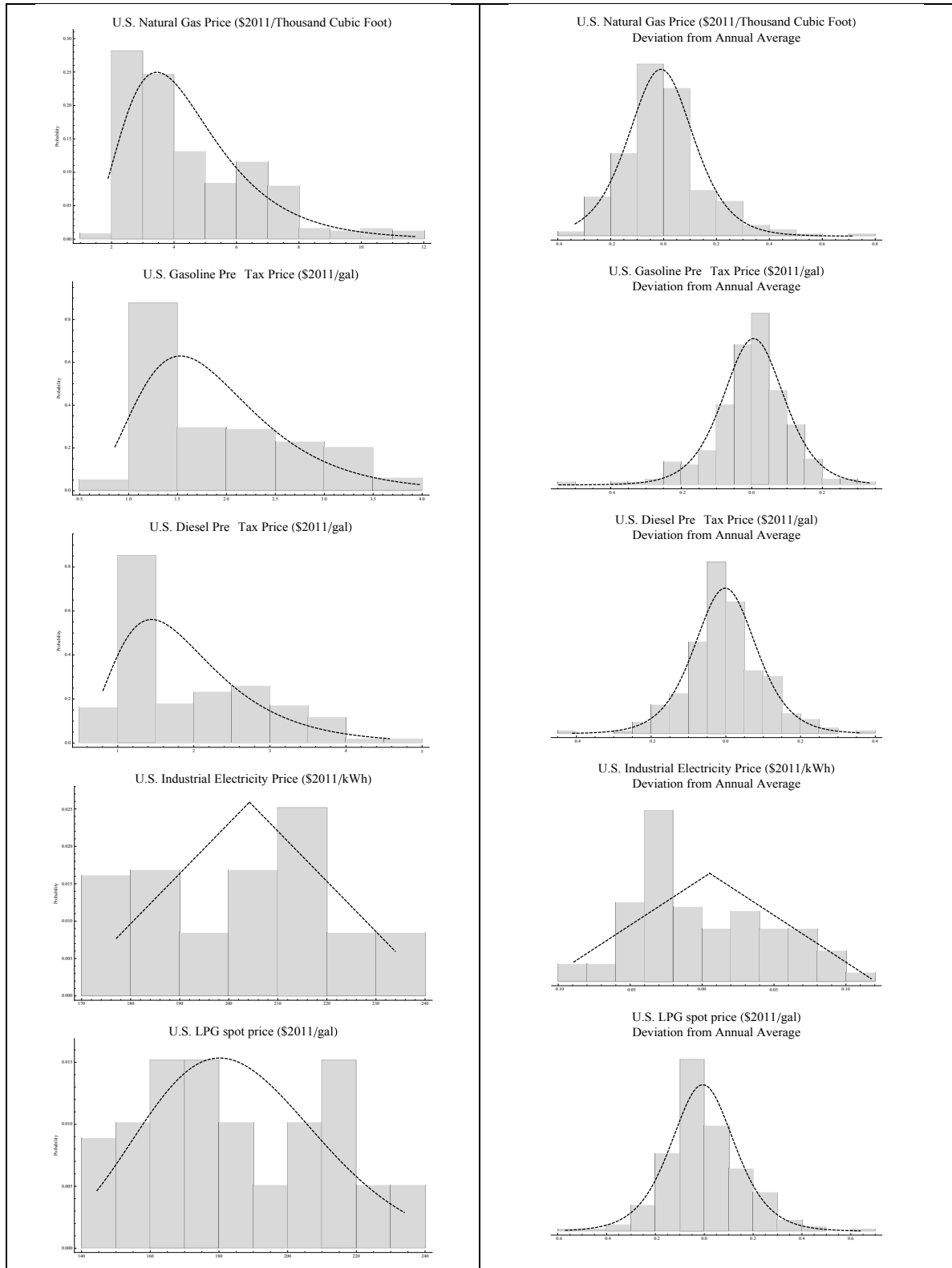
Figure S2.2. Comparison of price histograms and probability density function fits.

Table S2.3. Compositions of biomass feedstocks

Scenario	Pathway	Biomass feedstock type	Ultimate analysis (dry basis) (wt %)	Moisture content (wt%)
S1 (29)	HTG & FTS	Stover	Ash 6.0; C 47.3; H 5.1; N 0.8; Cl 0; S 0.2; O 40.6	25.0
S2 (29)	LTG & FTS	Stover	Ash 6.0; C 47.3; H 5.1; N 0.8; Cl 0; S 0.2; O 40.6	25.0
S3 (69)	BFPH	Stover	Ash 6.0; C 47.3; H 5.1; N 0.8; Cl 0; S 0.2; O 40.6	25.0
S4 (70)	JFPH	Hybrid poplar	N/A	50.0
S5 (71)	IHG & AAS	Hybrid poplar	N/A	50.0
S6 (71)	DHG & AAS	Hybrid poplar	N/A	50.0
S7 (72)	EH	Stover	Ash 6.0; C 47.3; H 5.1; N 0.8; Cl 0; S 0.2; O 40.6	25.0
S8 (74)	MTG	Hybrid poplar	Ash 1.0; C 50.9; H 6.0; N 0.2; Cl 0; S 0.1; O 41.9	50.0
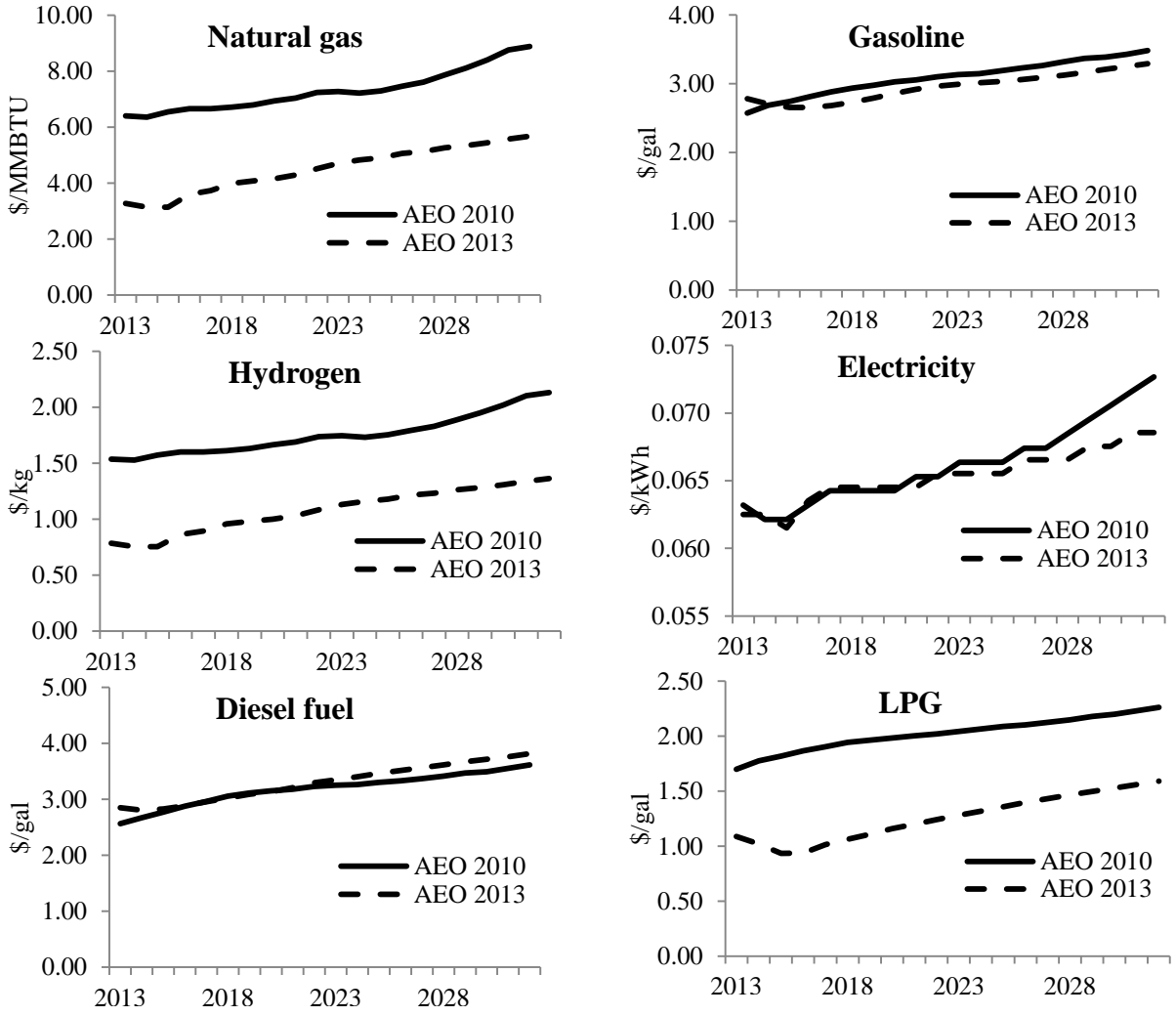
Figure S2.3. Projected annual prices from AEO 2010 and AEO 2013

4.1.3.   Cellulosic Biofuel Pathway Descriptions

Figure S2.4 includes schematics of the pathways underlying the eight scenarios analyzed in this study. The fast pyrolysis, gasification with FTS, and gasification with AAS pathways each have two scenarios included in this study. The two fast pyrolysis scenarios are based on two studies of the same pathway; the primary differences between the two are the assumed capital cost factors and fuel yields. The two scenarios for the gasification with FTS and gasification with AAS pathways are based on pathway variations. All of the pathways analyzed convert lignocellulosic biomass into transportation fuels. Most of the pathway scenarios yield drop-in biofuels, although the EH and AAS scenarios yield ethanol. As noted earlier, some of these scenarios employ hydrogen derived from an external source. Brief descriptions of the pathways follow below.

4.1.4.   Fast pyrolysis and Hydroprocessing

Fast pyrolysis is the rapid thermal decomposition of biomass in the absence of oxygen to liquid (bio-oil), solid (char), and gaseous (non-condensable gases, or NCG) co-products. Bio-oil can be upgraded either catalytically via fluid catalytic cracking or with hydrogen via hydroprocessing to hydrocarbon-based gasoline and diesel fuel. Hydroprocessing is a two-stage upgrading process consisting of an initial low-severity hydrotreating step, which stabilizes and partially deoxygenates the bio-oil, and a subsequent higher-severity hydrocracking step, which fully deoxygenates and depolymerizes the hydrotreated bio-oil to monomeric hydrocarbons (see Figure S2.4-a). This hydrogen can be produced either by reforming a portion of the bio-oil produced via fast pyrolysis or reforming merchant natural gas; the former results in lower fuel yields while the latter increases the operating costs by adding an input (93).

4.1.5. Gasification and AAS

Gasification is the thermal decomposition of biomass at temperatures of up to 1500°C

to a gaseous mixture of carbon monoxide (CO), hydrogen, methane, CO_2, and lesser amounts

of light hydrocarbons. This product is known as synthesis gas, or syngas, and a number of

routes exist for reacting clean syngas with catalysts or biocatalysts to produce liquid

transportation fuels, including ethanol (71), gasoline (74), and diesel fuel (29). Although

small amounts of char can be produced via biomass gasification, no bio-oil is produced and

the primary product is syngas.

The AAS pathway employs multiple process steps to convert biomass to ethanol via

gasification (see Figure S2.4-b) (71). The raw syngas is cleaned, at which point the CO and

H_2 in the clean syngas are then reacted over a ZnO/CuO catalyst to yield methanol, which is

distilled and in turn reacted with an iridium- and iodide-based catalysts to produce acetic

acid. Finally, the acetic acid is reacted with hydrogen via hydrogenation to yield ethanol and

water, which is distilled to produce fuel-grade ethanol.

4.1.6. Gasification and FTS

The gasification and FTS pathway (see Figure S2.4-c) resembles the AAS pathway in

that the product syngas must be thoroughly cleaned to remove any impurities capable of

poisoning the pathway catalysts. The CO and H_2 in the clean syngas are reacted over a

cobalt, iron, or ruthenium catalyst to yield long-chain alkanes and hydrocarbon waxes. Both

can be depolymerized to shorter hydrocarbon chains (so-called Fischer-Tropsch liquids) that

can serve as refinery blendstock for the production of gasoline and diesel fuel.

4.1.7. Gasification and MTG Synthesis

The gasification and MTG synthesis pathway is similar to the gasification and AAS pathway in that the CO and H_2 in clean syngas are catalytically reacted to synthesize methanol. The pathways diverge after methanol synthesis, however, as the MTG pathway employs a methanol dehydration step to yield dimethyl ether (DME) (see Figure S2.4-d). The DME is reacted over a zeolite catalyst as a final step to yield a blend of aromatics and alkanes in the gasoline boiling range (74). A significant advantage of the MTG synthesis pathway over the FTS pathway is that the hydrocarbon synthesis products generally do not require depolymerization to short-chain alkanes, eliminating the need for hydrogen consumption via a hydrocracking step.

4.1.8. Enzymatic Hydrolysis and Fermentation

The production of ethanol via the enzymatic hydrolysis and fermentation pathway differs from the previous pathways in that it employs the biochemical platform rather than the thermochemical platform to both depolymerize lignocellulosic biomass and convert it to fuel. The fermentable monosaccharides glucose and xylose can be derived from cellulose and hemicellulose, respectively, and then fermented to ethanol. In addition to not being fermentable, however, lignin has anti-microbial properties that inhibit biochemical activity. The pathway therefore employs a feedstock pretreatment to separate the cellulose and hemicellulose from the lignin, which is combusted to provide electricity, and hydrolyze the hemicellulose to xylose. Following pretreatment, a system of cellulase enzymes is employed to hydrolyze the cellulose to glucose (96). The resulting monosaccharides are then fermented to ethanol, which is distilled to yield fuel ethanol (see Figure S2.4-e).
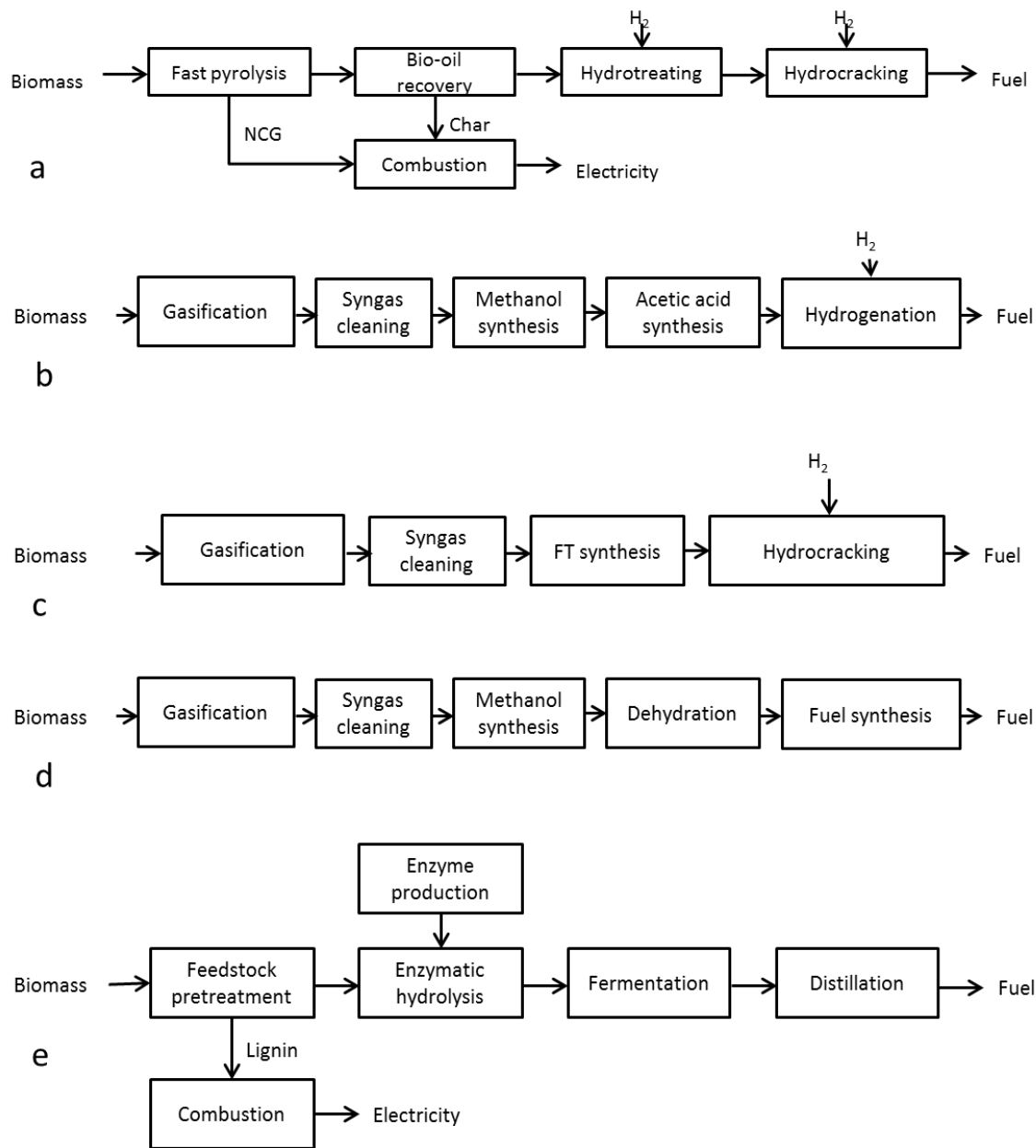
Figure S2.4. Schematics of pathways analyzed. a – fast pyrolysis and hydroprocessing; b – gasification and AAS; c – gasification and FTS; d – gasification and MTG synthesis; e – enzymatic hydrolysis and fermentation.

CHAPTER 3. A FRAMEWORK FOR DEFINING THE ECONOMIC FEASIBILITY OF
CELLULOSIC BIOFUEL PATHWAYS

A paper submitted for publication in the international refereed journal *Biofuels*

Tristan R. Brown[4] and Mark M. Wright[5]

3.1.   Abstract[6]

This paper incorporates pathway-specific financial assumptions into techno-economic analyses of cellulosic biofuel pathways under price uncertainty. Five cellulosic biofuel pathway scenarios are developed in a discounted cash flow rate of return spreadsheet to determine pathway-specific costs of debt. Cost of equity for the scenarios is calculated based on the financial characteristics of the U.S. biorenewable industrial sector. A 20-year net present value (NPV) and probability of default for each scenario are stochastically calculated. Mean NPVs vary from a low of -\$774 million to a high of -\$135 million. Probabilities of default range from a high of 100% to a low of 80.5%. A sensitivity analysis finds that the use of pathway-neutral financial assumptions overestimates NPV and underestimates probability of default.

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[5] Assistant professor in Department of Mechanical Engineering, Iowa State University; corresponding author.
[6] AEO = Annual Energy Outlook; CADS = cash available for debt service; CAPM = Capital Asset Pricing Model; DSCR = debt service coverage ratio; DCFROR = discounted cash flow rate of return; EBIT = earnings before interest and tax; EH = enzymatic hydrolysis and fermentation to ethanol; EIA = Energy Information Administration; EPA = Environmental Protection Agency; FPH = fast pyrolysis and hydroprocessing; FCI = fixed capital investment; FTS = Fischer-Tropsch synthesis; HTG = high-temperature gasification; IB = enzymatic hydrolysis and fermentation to isobutanol; ICR = interest coverage ratio; IRR = internal rate of return; LTG = low-temperature gasification; MMGPY = million gallons per year; MSFP = minimum fuel selling price; MT = metric ton; NPV = net present value; RFS2 = revised Renewable Fuel Standard; TEA = techno-economic analysis.

3.2.   Introduction

One of the biggest challenges of the U.S. biofuels mandate, the revised Renewable Fuel Standard (RFS2), has been the inability of cellulosic biofuel pathways to produce more than a tiny fraction of the volumes required by the mandate to date. Created by Congress in 2007 to replace the obsolete original Renewable Fuel Standard (RFS1), the RFS2 establishes annual volumetric biofuel blending mandates that steadily increase from a total of 9 billion gallons on an ethanol-equivalent basis in 2008 to 36 billion gallons by 2022 (2). The majority of production in the later years of the mandate is to be accounted for by biofuels derived from lignocellulosic feedstocks, the mandated volume of which rapidly increases from zero in 2008 to 16 billion gallons (ethanol-eq.) in 2022. A number of cellulosic feedstocks are expected to contribute to this volume by 2022, with corn stover expected to be one of the primary contributors by weight (26). Investment in cellulosic biofuel capacity to date has been much lower than needed to produce the necessary volumes even in the RFS2's early years, however. As a result the Environmental Protection Agency (EPA), which oversees the RFS2, has revised the cellulosic biofuel volumes for 2010 through 2014 down by as much as 99% in response (see Figure 3.1). Even the revised volumes have proven to be overly-optimistic in retrospect, however: zero gallons of cellulosic biofuel were blended in 2010 and 2011 (versus 6.5 million gallons and 6.0 million gallons revised, respectively), while only 0.02 million gallons and an estimated 0.82 million gallons were produced in 2012 and 2013 (versus 10.5 million gallons and 14.0 million gallons revised, respectively) (5). The EPA recently revised the 2014 cellulosic biofuel volume down from 1750 million gallons to 17 million gallons as capacity investment has continued to remain very low (24).
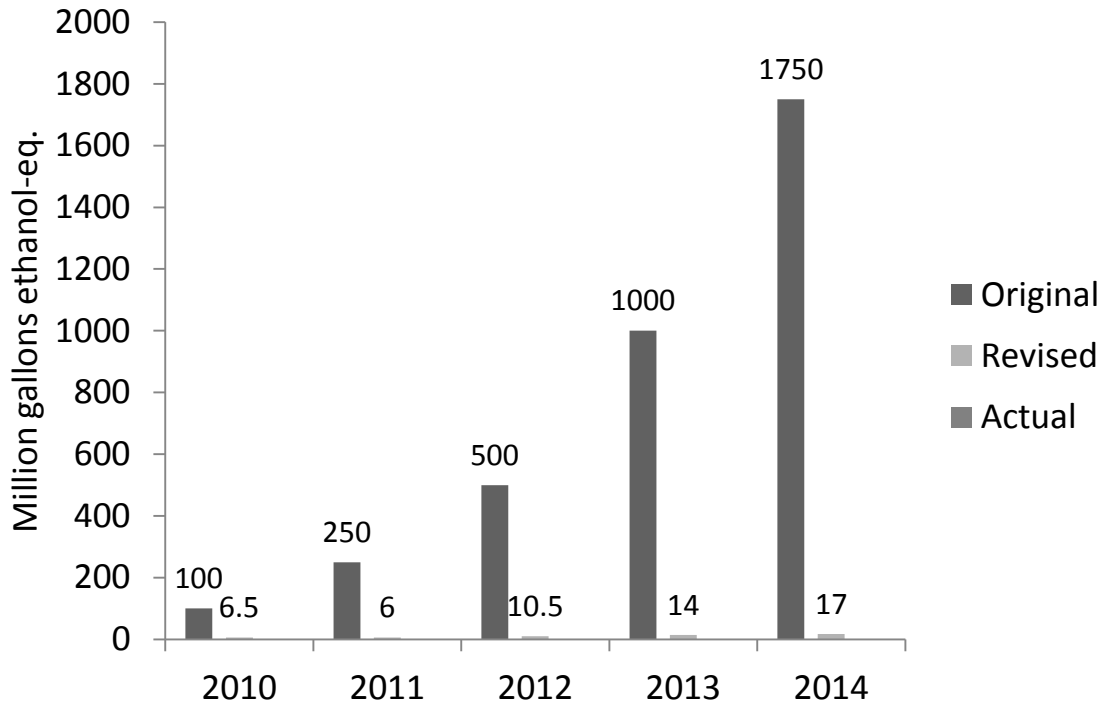
Figure 3.1. Originally-mandated, revised, and actual RFS2 cellulosic biofuel blending volumes, 2010-2014. 2013 actual volume estimated based on blending data through October 2013 (2,5,24).

The explanation for the lack of necessary capacity investment that is most commonly reported in the media is cellulosic biofuels' inability to compete in today's energy market, especially in light of its high capital costs. For example, multinational energy corporation Chevron determined in 2010 that investments in cellulosic hydrocarbon production generated only half of the return generated by conventional energy investments, causing it to scrap $400 million in planned capacity investment (97). Multinational energy companies such as BP, Exxon Mobil, and Royal Dutch Shell have all made similar decisions in recent years for the same reason (98). These decisions have been supported by a 2011 report released by the National Research Council and published by the National Academy of Sciences (99), which relied upon techno-economic analyses (TEA) of three cellulosic biofuel pathways to arrive at

the conclusion that cellulosic biofuels will only be cost-competitive with petroleum-based fuels in an economic scenario in which high petroleum prices (> $191/bbl), technological breakthroughs, and a high carbon price are the norm. However, this result is incongruous with a number of recent TEAs in the literature calculating cellulosic biofuel production costs to be below projected gasoline and diesel fuel prices (69,74,85,93,100,101), indicating that the latter calculations could be improved to better reflect the reality of cellulosic biofuel investment projects.

TEA is a methodology employed to estimate the production costs of energy pathways based on discounted cash flow rate of return (DCFROR) analysis. It is frequently used to estimate the production costs of biorenewable pathways that have yet to achieve commercialization. By calculating the production costs of various cellulosic biofuel pathways, TEA can be used to broadly estimate their economic feasibility for years in which petroleum price projections are also available (99). This use of TEA requires the accurate modeling of the specific technical and economic operating conditions of each pathway. A shortcoming of the current TEA methodology that is often employed to compare different pathways is that it treats technical conditions and economic or financial conditions differently: while the exact technical specifications of each pathway are carefully modeled, generic economic and financial assumptions are made that are identical across all pathways. For example, economic feasibility is commonly defined according to a financial standard, such as a minimum fuel selling price (MSFP) that is lower than the biofuel's market value (99) or a 20-year internal rate of return (IRR) that exceeds an arbitrary benchmark (102,103). Furthermore, the results of cellulosic biofuel pathway TEAs are highly uncertain due to the lack of commercialization in the sector. While some energy pathway TEAs attempt to

quantify this uncertainty by computing probability distributions via stochastic simulations (83,86,88), these analyses commonly employ statistical fit distributions that do not accurately reflect the range of potential values (87).

The use of a common set of economic and financial assumptions when completing TEAs of multiple pathways ignores their strong sensitivity to a pathway's technical specifications. Factors such as pathway yield, input requirements, and product portfolio have a large impact on the size and variability of the pathway's cash flows, which in turn are used to calculate economic feasibility metrics such as MFSP, IRR, and net present value (NPV). A recent comparison of eight different cellulosic biofuel pathway TEAs under price volatility and identical economic and financial assumptions found that both the mean and standard deviation of 20-year NPVs vary widely across pathways due to the influence of these factors, with the means ranging from a low of -$590.2 million for enzymatic hydrolysis and fermentation to a high of $274.8 million for fast pyrolysis and hydroprocessing (104). That comparison employed a 10% discount rate and 7.5% interest rate for each pathway; in reality, however, investors and creditors require both of these to be a function of NPV and cash flow variability, with higher costs of equity and/or debt required for those pathways that are expected to generate lower NPVs and/or higher cash flow variability. Given this wide variation in expected returns across cellulosic biofuel pathways, then, an accurate TEA comparison needs to treat each pathway's financial assumptions subjectively as differences between them will affect their economic feasibility determinations.

This analysis presents a framework for integrating TEAs of cellulosic biofuel pathways with uncertainty analysis to quantify the costs of debt and equity for each pathway. DCFROR spreadsheet models are created using cellulosic biofuel pathway data in the

techno-economic literature to quantify pathway economic feasibility. Pathway selection is based on those stover-based cellulosic biofuel pathways or their variants that are currently undergoing commercialization within the U.S. (27) and for which recent TEAs are available in the refereed literature. Uncertainty analysis is performed via Monte Carlo simulation to quantify pathway cash flows under commodity price uncertainty, which affects both pathway costs and revenue. The framework is then employed to quantify pathway-specific costs of debt and equity and to demonstrate the sensitivity of each pathway's economic feasibility determination to these financial costs.

3.3.   Methodology

This analysis employs the following framework to incorporate pathway-specific financial costs into the economic feasibility quantification: (1) process and economic data of select stover-based cellulosic biofuel pathways are collected and adjusted; (2) historical data on monthly commodity price variation distributions are fit to probability distributions; (3) 20-year cash flows are deterministically simulated to calculate interest coverage ratios (ICR) for each pathway; (4) costs of debt and equity are calculated for each pathway as a function of their ICRs and industry betas, respectively; and (5) 20-year NPV distributions and 10-year probabilities of default are estimated for each pathway scenario as a function of stochastic cash flow simulation and cost of debt and equity calculations. Steps 1,2 and 5 are adopted from a previous comparative TEA of cellulosic biofuel pathways under uncertainty (104) while Steps 3 and 4 are unique to this analysis, as are the probability of default calculations. The methodology is illustrated in Figure 3.2.
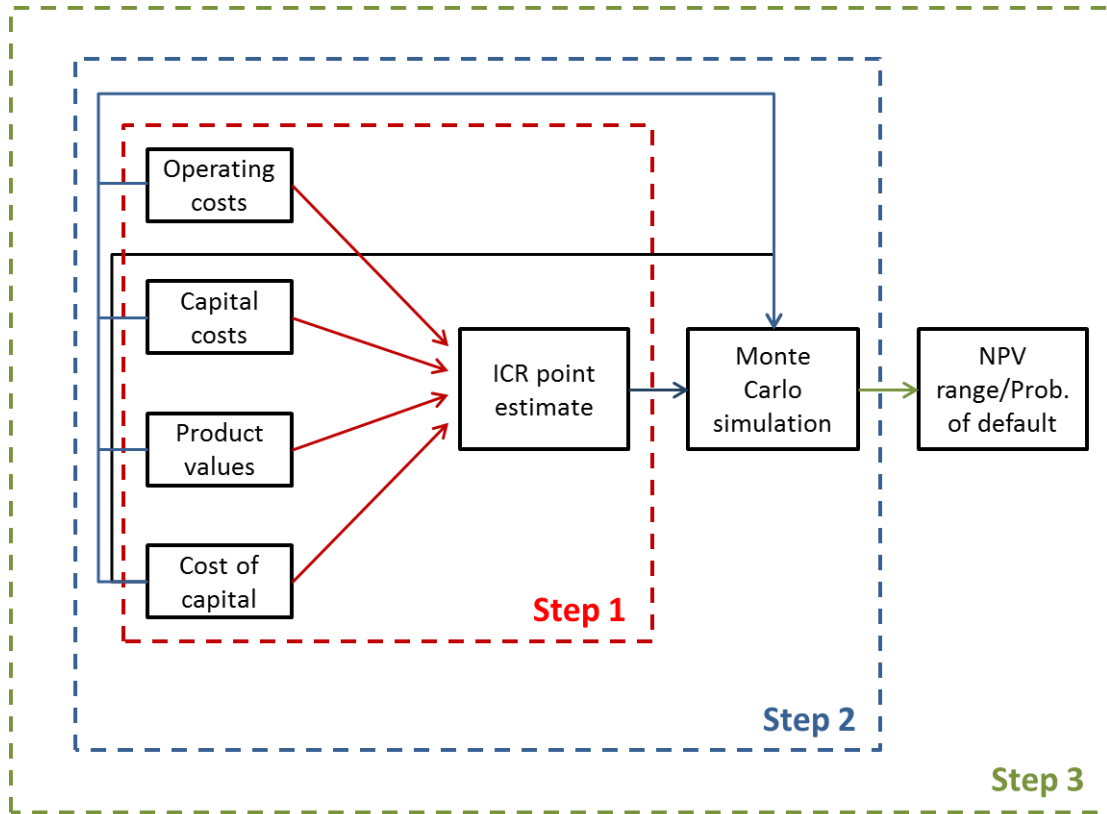
Figure 3.2. Illustration of analysis methodology

Four different pathways are selected to develop five pathway scenarios with facility capacities of 2000 metric tons (MT)/day: (1) high-temperature gasification and Fischer-Tropsch synthesis (HTG & FTS); (2) low-temperature gasification and Fischer-Tropsch synthesis (LTG & FTS); (3) fast pyrolysis and hydroprocessing (FPH); (4) enzymatic hydrolysis and fermentation to ethanol (EH); and (5) enzymatic hydrolysis and fermentation to isobutanol (IB). The process data for the two gasification and FTS scenarios are based on an analysis by Swanson et al. (29). The FPH scenario is derived from an analysis by Brown et al. (69) and the EH scenario is based on an analysis by Kazi et al. (72). Finally, the IB scenario is developed from an analysis by Tao et al. (40). The original process conditions for each scenario are summarized in Table 3.1.

Table 3.1. Pathway scenario mass balances and annual operating hours. All scenarios assume 2000 MT (dry)/day of biomass input.

Scenario	Pathway	Operating hours/yr	Net electricity required (MW)	External H_2 consumption (MT/day)	Gasoline-eq. output (MMGPY)	Diesel fuel output (MMGPY)
S1	HTG & FTS	7446	-13.8	0	12.9	25.8
S2	LTG & FTS	7446	-16.4	0	10	20
S3	FPH	7900	-28.2	49.1	28.7	28.7
S4	EH	8400	-25.8	0	35.6	0
S5	IB	8400	-27.7	0	37.0	0

Multiple adjustments are made to the scenarios to account for major differences between the analyses on which the pathway scenarios are based. First, input and output prices are assumed to be the same for each pathway scenario. While these prices can be expected to vary across U.S. regions (32), this analysis makes this assumption for the sake of simplification and to remove regional price variation as a sensitivity factor. Second, all dollar figures are adjusted to a 2011 basis using the U.S. city average Consumer Price Index as the cost multiplier (76). Finally, the assumed feedstock cost has been adjusted to $116.37/MT for all of the scenarios based on a techno-economic analysis of stover production and collection by Shah and Darr (2013) (105). Shah and Darr calculate a base case stover cost of $117/MT under a diesel fuel price of $3.50/gal and diesel fuel consumption of 3 gal/MT. The present analysis assumes an initial after-tax diesel price of $3.29/gal and the assumed $116.37/MT stover price reflects this reduced price. This analysis further assumes that farmer participation in stover harvesting is 50% (as opposed to the 30% value assumed by Shah and Darr) so as to ensure sufficient stover supply for a 2000 MT/day cellulosic biofuel facility. A 50% participation rate is assumed in other stover supply analyses (106,107) and has been

identified as the target rate for cellulosic biofuel producers (108). Other differences, such as

capital cost calculation methodology and annual operating hours, remain unchanged from the

original analyses. Table 3.2 summarizes the capital and operating costs for each of the

pathway scenarios on an adjusted basis.

Table 3.2. Capital and operating costs of pathway scenarios adjusted 2011 US dollar cost basis

Scenario	Total project investment (MM$)	Fixed operating cost (MM$/yr)	Co-product credit (MM$/yr)	H_2 cost (MM$/yr)	Other variable cost (MM$/yr)	Working capital % of FCI
S1	657.4	15.5	6.8	0	12.6	30.4
S2	540.3	30.1	8.1	0	13.1	30.8
S3	429.0	12.4	14.8	32.5	1.8	29.7
S4	407.9	10.7	15.6	0	67.2	31.8
S5	461.0	11.7	6.4	0	29.2	30.9

The Monte Carlo simulation employed by this analysis requires probability

distributions to be selected for each of the commodity prices covered. These commodities are

diesel fuel, electricity, gasoline, hydrogen (produced from natural gas via SMR), natural gas,

and stover. They are selected due to (1) their use in cellulosic biorefineries and (2) the

availability of sufficient historical monthly price data from which to identify probability

distributions. The exception to the second criterion is stover, for which there currently exists

no market from which prices can be identified. This analysis employs historical corn prices

as a proxy from which to develop the price distribution for stover that is applied to the stover

cost calculated by Shah and Darr (105). While the two feedstocks are used for different

pathways, stover is a byproduct of corn production and stover yields are closely correlated to

corn yields.

The distribution selection methodology employed in this analysis is described in detail in a separate paper (104). An important difference between this analysis and the previous paper is that the former derives its probability distributions from the historical monthly price change over the previous month, rather than relative to the historical annual average price. This change places less certainty on average annual commodity price projections for the next 20 years and does not assume that prices will revert to the projected averages. The motivation behind this change is the underestimation of unforeseen abrupt changes and future consumption by previous long-term U.S. energy forecasts (109,110). For example, as late as 2010 the EIA projected a U.S. natural gas price for 2012 that ended up being 200% higher than the actual price for the year due to the unanticipated exploitation of domestic shale gas reserves and resulting surge in production (79,111). This analysis therefore considers price projection uncertainty rather than just price volatility, resulting in a broader range of projected price outcomes.

The best distributions for each commodity price are selected on the basis of the Anderson-Darling goodness-of-fit test results (91). The historical price changes are collected for the years 1993 to 2012 when available. Table 3.**3** presents the distribution selected for each commodity price. To prevent unrealistic monthly price changes, each distribution is truncated to include those values falling within a 95% confidence interval (CI). Note that the hydrogen price is calculated as a function of the natural gas price given that half of global hydrogen production derives from natural gas reforming (112).

Table 3.3. Probability distribution function for monthly change of
each commodity price

Commodity	Distribution	Monthly price change range (95% CI)	Historical data years and source
Electricity (industrial)	Lognormal	-5.4% 6.4%	2001-2012 (113)
Diesel fuel	Logistic	-10.9% 11.1%	1994-2012 (114)
Gasoline	Logistic	-14.6% 14.7%	1993-2012 (115)
Natural gas (Henry Hub)	Logistic	-22.5% 23.0%	1993-2012 (111)
Hydrogen[a]	Logistic		-
Stover[b]	Logistic	-11.0% 11.0%	1993-2012 (116)

[a]Calculated as a function of natural gas price (80)
[b]Distribution based on historical corn prices due to lack of a
developed stover market

4.1.9. Cost of equity

This analysis calculates a cost of capital for each pathway scenario based on its

respective pathway economics. A firm's cost of capital consists of both its cost of equity and

cost of debt. The cost of equity is employed in the DCFROR model as the discount rate/IRR

while the cost of debt is used to calculate interest expense within the model. The former is

the rate of return investors require on an equity investment in a firm (117). Investors require

a higher rate of return relative to the riskless rate from high-volatility investments than from

low-volatility investments as compensation for the increased risk of the former. A publicly-

traded firm's cost of equity can be calculated via the Capital Asset Pricing Model (CAPM) as

a function of its historical stock returns relative to those of the market (also known as its

"historical market beta"). The CAPM formula is:

$$E(R_i) = R_i + \beta_i[E(R_m) - R_i]$$

where $E(R_i)$ is the expected return on asset i, R_i is the risk-free rate, $E(R_m)$ is the expected

return on a market portfolio, and β_i is the beta of asset i.

When the firm being analyzed is either privately-held or hypothetical, the latter being

the case in this analysis, then there is no market beta from which to calculate $E(R_i)$. An

alternative approach, which is adopted here, uses the betas of the publicly-traded firms

belonging to the same industrial sector as the firm being analyzed as a proxy beta (or

"bottom-up beta") (118). The pathway scenarios presented in Table 3.1 are selected due to

their employment (or the employment of a closely-related variant pathway) by existing or

planned commercial-scale cellulosic biofuel facilities in the U.S. (27). Furthermore, several

companies engaged in the production of either advanced biorenewable products, including

biofuels (defined here as biorenewable pathways other than corn ethanol), or advanced

biorenewable feedstocks have successfully staged initial public offerings (IPO) in recent

years. This analysis calculates historical market betas for each of these publicly-traded

companies based on their weekly stock returns from the date of their IPO to December 2,

2013 using the following formula to regress stock returns against market (defined here as the

S&P 500 index) returns (117):

$$R_s = a + b\,R_m$$

where R_s is the stock return, R_m is the market return, *a* is the regression intercept, and *b* is the

slope of the regression. Each return for the stocks and the overall S&P 500 is calculated as:

$$\text{Return}_j = (\text{Adj. price}_j - \text{Adj. price}_{j-1})/\text{Adj. price}_{j-1}$$

where *j* is the week for which the return is calculated and Adj. price is the return plus any

dividends. The calculated stock betas and their respective standard errors are presented in

Table 3.4. One outlier was removed from the quarterly data for a period when the

shareholder equity of Amyris fell to just above zero, resulting in a much higher-than-average

debt/equity ratio for that quarter (6,015%).

Table 3.4. Advanced biorenewable companies historical market betas

Name	Ticker	Beta	Std. error	Market debt/equity ratio[a]	Effective tax rate
Amyris	AMRS	1.68	0.42	82.1%	0%
Codexis	CDXS	2.23	0.29	0%	0%
Gevo	GEVO	2.14	0.44	36.5%	0%
FutureFuel	FF	1.10	0.19	0%	35.8%
KiOR	KIOR	0.96	0.50	42.1%	0%
Metabolix	MBLX	1.22	0.44	0%	0%
Syntroleum	SYNM	1.38	0.37	0%	0%
Solazyme	SZYM	1.58	0.30	25.7%	0%
Verenium	VRNM	0.95	0.36	390.0%	0%
Mean	--	1.47	0.37	64.0%	4.0%
Std. dev.	--	0.48	0.10	125.3%	12.0%

Source: Yahoo Finance
[a]Quarterly average since Q1 2011 or date of IPO (if more recent)

For practical purposes, the use of the biorenewable sector beta as a proxy beta for the

hypothetical firms simulated in this analysis enables the calculation of non-arbitrary discount

rates for each pathway scenario. Using the average beta from Table 3.4 within the CAPM

formula yields a cost of equity of 10.0%, assuming a risk-free 20-year Treasury bond rate of

3.7% (119) and market risk premium of 4.3% (the geometric-mean risk premium for U.S.

stocks over Treasury bonds from 1928 to 2010) (117). This is identical to the discount rate

employed by a number of recent techno-economic analyses of cellulosic biofuel pathways

(69,74,104,120–124). What this calculation doesn't account for, however, is the sensitivity of

the advanced biorenewable sector's betas to its relative lack of development. Whereas the

U.S. corn ethanol sector has an average facility capacity of 71.4 million gallons per year

(MMPGY) as of November 2013 (125), the largest cellulosic biofuel facility currently

operating is KiOR's 14 MMGPY facility in Columbus, Mississippi (126). Based on current

and proposed facility construction, the average U.S. cellulosic biofuel facility capacity is expected to be only 29.6 MMGPY by 2015 (27). The advanced biorenewable sector has seen more U.S. capacity investment than the cellulosic biofuel sector, although of the companies listed in Table 3.4 only Syntroleum (127) and Future Fuel (128) have existing advanced biofuel capacities in excess of 30 MMGPY (the former's capacity taking the form of a joint venture). The remaining companies must raise additional capital prior to investing in commercial-scale capacity and much of this can be expected to come in the form of debt, thereby increasing their market debt/equity ratios. The current state of the corn ethanol sector, which is more mature than the advanced biorenewable and cellulosic biofuel sectors and owns much more existing capacity, provides some support for this assumption. Table 3.5 lists the debt/equity ratios and effective tax rates for the four publicly-traded independent corn ethanol producers in the U.S., which have a combined biofuel capacity of roughly 1500 MMGPY. In addition to being characterized by a higher average market debt/equity ratio than the advanced biorenewable sector, the corn ethanol sector also has a higher effective tax rate. This is due to the fact that the majority of the companies listed in Table 3.4 have no taxable income and therefore also have an effective tax rate of 0%. As with Table 3.4, a single outlier was removed from Table 3.5 for a quarter when Pacific Ethanol's shareholder equity fell sharply and resulted in a quarterly market debt/equity ratio of 6,988%.

Table 3.5. Publicly-traded independent corn ethanol companies

Name	Ticker	Market debt/equity ratio	Effective tax rate
Biofuel Energy	BIOF	266.1%	0%
Green Plains Renewable Energy	GPRE	137.3%	44.7%
Pacific Ethanol	PEIX	320.3%	0%
REX American Resources	REX	36.1%	22.6%
Mean	--	171.6%	16.8%

Table 3.5 continued			
Name	Ticker	Market debt/equity ratio	Effective tax rate
Std. dev.	--	118.3%	21.4%

Source: Yahoo Finance

The present analysis assumes that commercial-scale facilities are operating for each

cellulosic biofuel pathway scenario considered and therefore adjusts the average beta for the

advanced biorenewable sector to account for this. Using the methodology described by

Damodaran (2012) (117), an unlevered beta is first calculated via the following formula

(117):

$$\beta_u = \beta/[1 + (1 - t) \times (D/E)]$$

where β_u is the unlevered beta for equity in a firm, β is the beta for equity in a firm, t is the

firm's effective tax rate, and D/E is the firm's market debt/equity ratio. The unlevered beta

disregards the effect of the debt/equity ratio and a value of 0.91 is calculated for the

biorenewable sector. The unlevered beta is then levered using the desired debt/equity ratio; in

this case a debt/equity ratio of 171.6% is employed to yield a levered beta of 2.48. When

used in the CAPM formula with the 20-year Treasury yield of 3.7% and the historical market

risk premium of 4.3%, this levered beta yields a cost of equity for the cellulosic biofuel

sector of 14.3%, or 43% higher than the value commonly used in cellulosic biofuel techno-

economic analyses.

4.1.10. Cost of debt

Cost of debt is calculated as a function of both a firm's debt/equity ratio and its cash

flows, the latter determining whether the firm has sufficient cash to meet its interest

payments and debt repayment. As with cost of equity, cost of debt is commonly calculated

based on existing financial records – in this case, the interest rates paid either by the firm or

by other firms in the same industrial sector. Such a methodology is not suitable here due to

the lack of cellulosic biofuel commercialization and a relative lack of debt in the advanced

biorenewable sector (which is also due to a lack of commercialization to date). This analysis

instead employs the interest coverage ratio (ICR) of each hypothetical stand-alone facility to

determine cost of debt based on the relationship between the two in the broader market (see

Table 3.6) (117,118).

Table 3.6. ICRs and ratings for low
market-capitalization firms (117)

Interest coverage ratio	Rating	Spread
>12.5	AAA	0.50%
9.5 - 12.5	AA	0.65%
7.5 – 9.5	A+	0.85%
6.0 – 7.5	A	1.00%
4.5 – 6.0	A-	1.10%
3.5 – 4.5	BBB	1.60%
3.0 – 3.5	BB	3.35%
2.5 – 3.0	B+	3.75%
2.0 – 2.5	B	5.00%
1.5 – 2.0	B-	5.25%
1.25 – 1.5	CCC	8.00%
0.8 – 1.25	CC	10.00%
0.5 – 0.8	C	12.00%
<0.5	D	15.00%

ICR is calculated by the following formula:

$$\text{Interest coverage ratio} = \frac{\text{EBIT}}{\text{Interest expense}}$$

where EBIT is earnings before interest and taxes. The spreadsheet model is used to

deterministically calculate base case monthly ICRs for each pathway scenario under the risk-

free rate and the calculated cost of equity, from which a mean ICR for the 10-year loan term

is derived. The appropriate interest spread from Table 3.6 is then selected based on the

respective ICR and added to the risk-free rate to calculate a loan interest rate for each

pathway scenario. The spreadsheet model is changed to reflect this new interest rate and the process is repeated deterministically until the ICR and the interest rate converge. The converged deterministic ICR values are used to calculate mean stochastic ICRs for each scenario and the process is again repeated until the ICRs and interest rates converge. The final selected interest rates for each pathway scenario are presented in Table 3.7.

Table 3.7. Pathway scenario interest coverage ratios and interest rates

Scenario	Mean stochastic ICR	Interest rate
S1	-0.67	18.7%
S2	-0.99	18.7%
S3	0.49	18.7%
S4	-1.69	18.7%
S5	-1.05	18.7%

4.1.11. Monte Carlo simulation

The final step of this analysis stochastically calculates a 20-year NPV probability distribution and 20-year probability of default for each pathway scenario based on the values in Table 3.2, Table 3.**3**, and Table 3.7. This analysis adopts the approach presented by Esty (1999) (129) for simulating future commodity prices and all commodity price changes are assumed to follow a random walk with drift within the Monte Carlo simulation. The monthly changes for each commodity are based on the respective distributions and truncations presented in Table 3.**3**. Furthermore, each commodity price is assumed to drift, with the drift set to the value required for the mean of each monthly price distribution to match the respective annual price projections published by the Energy Information Administration for 2013-2032 (19). Crystal Ball® is used to generate 10,000 random monthly price changes per commodity and month, with the price in one month (P_t) equaling the previous month's price plus the random change (129):

$$P_t = P_{t-1}(1 + \text{random change})$$

The generated monthly price changes over the 20-year period covered by the DCFROR model are aggregated to produce 10,000 random price paths for each commodity. The price volatility of each commodity is based on its respective historical volatility. Furthermore, the historical price data is also analyzed with Crystal Ball® to identify correlations between different commodity prices via Spearman's correlation coefficient. A very strong correlation (>0.9) is identified for the prices of gasoline and diesel fuel (0.981) while a strong correlation (>0.5) is identified for the prices of diesel and corn (the latter on which the stover cost distribution is based). The Crystal Ball® simulations account for these correlations so as to prevent unrealistic price movements between commodities (e.g., a sustained sharp divergence between the prices of gasoline and diesel fuel). Finally, the monthly prices generated by Crystal Ball® are used to generate the monthly cash flows from which a 20-year NPV probability distribution is derived for each pathway scenario.

The 20-year probability of default is also calculated stochastically for each pathway scenario alongside the 20-year NPV. Probability of default is defined here as the probability that the mean minimum debt service coverage ratio (DSCR) of a pathway scenario is less than 1, as presented by Esty (1999) (129). The DSCR is a function of the scenario's cash available for debt service (CADS), where CADS is defined as EBIT plus depreciation minus income tax, and DSCR is defined as CADS divided by loan principal repayment. The DSCR calculation is performed each quarter (rather than each month) to reflect the corporate practice of making cash distributions on a quarterly basis (i.e., this analysis assumes that all cash remaining at the end of each quarter is distributed or expended). Any quarter in which the DSCR falls below 1.0 indicates that the pathway scenario facility has insufficient cash to make its loan repayments for the period. Finally, because each pathway scenario assumes

that facility output is only 50% of maximum during the first six months of production, this analysis increases the working capital value for each pathway scenario to the amount necessary to cover loan repayments until maximum output is achieved (see Table 3.2). This prevents the facility's initial underperformance from affecting the probability of default result.

3.4.   Results

We calculate NPV and probability of default for five cellulosic biofuel pathway scenarios under electricity, diesel fuel, gasoline, natural gas, and stover price uncertainty. Four of the five pathway scenarios have very low probabilities of achieving NPVs that are greater than zero (see Figure 3.3). The HTG & FTS and LTG & FTS scenarios have probabilities of 0.3% and 0.04%, respectively. The EH and IB scenarios both achieve slightly higher probabilities of 0.9% and 1.2%, respectively. The FPH scenario has the highest probability of achieving a positive NPV at 27.2%. The FPH scenario also achieves the highest mean NPV at -$134.7 million. The NPV standard deviations for all of the scenarios are large due to the wide range of commodity prices simulated by the Monte Carlo analysis, with the LTG & FTS scenario achieving the smallest standard deviation at $161.4 million. The large standard deviations are expected due to the strong sensitivity of cellulosic biofuel pathways to the prices of the commodities considered in this analysis. The lowest maximum NPV is achieved by the HTG & FTS scenario, although even this exceeds $545 million when the Monte Carlo simulation generates diesel fuel, gasoline, and electricity prices that match or exceed their respective historical highs. Similarly, however, very low NPVs are reported

for all of the pathway scenarios when the Monte Carlo simulation generates high input costs and low output prices.
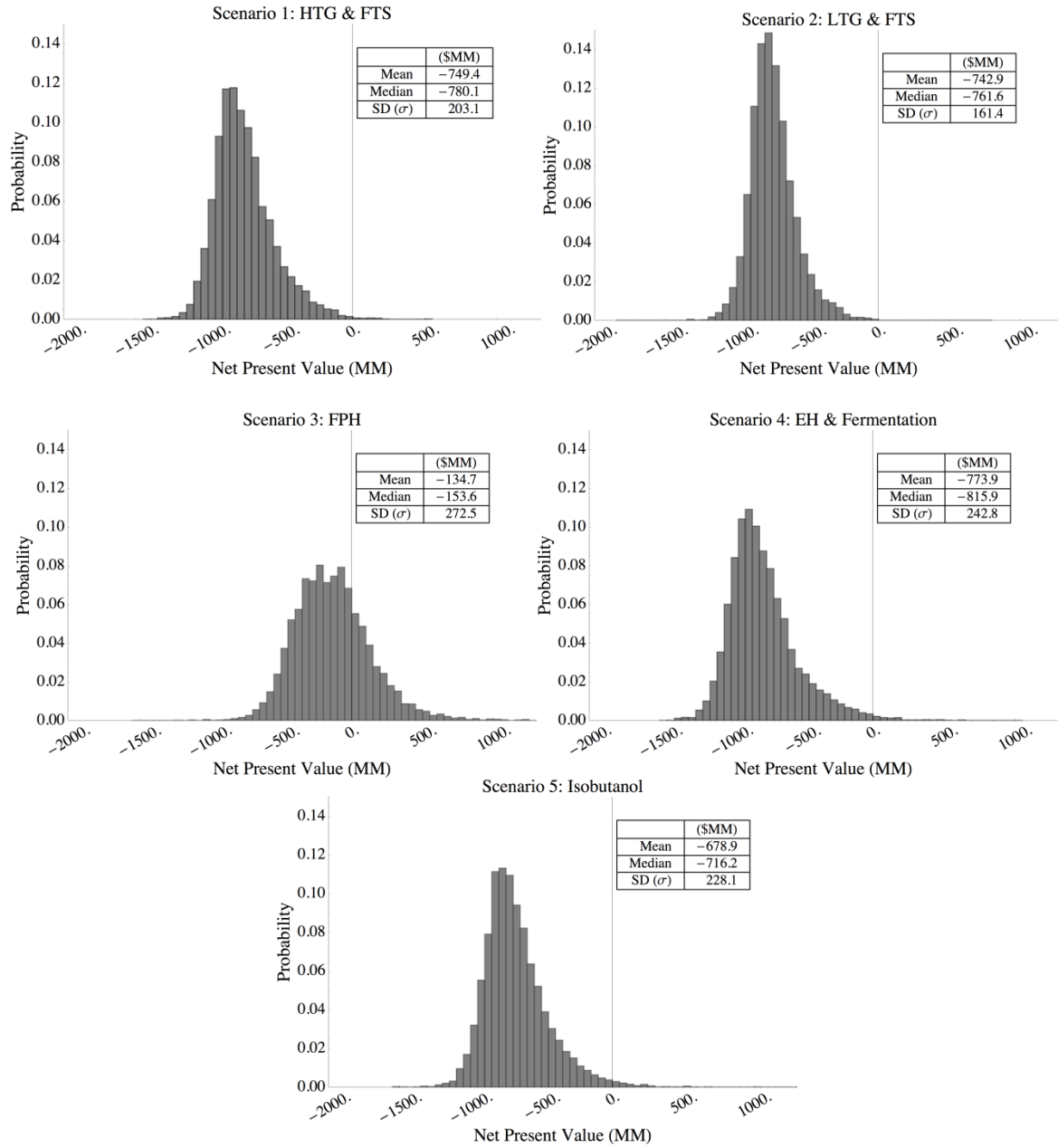
Figure 3.3. 20-year NPV results for five cellulosic biofuel pathway scenarios

The probability of default calculations present a slightly more optimistic result for the economic feasibility of the five pathway scenarios. While the HTG & FTS, LTG & FTS, and EH scenarios have a less than 1% probability of achieving positive NPVs, their probabilities of defaulting during the 10-year loan term are all 100%. The probability of default for the IB scenario is also 100%. The FPH scenario achieves the lowest probability of default, although it is still high at 80.5%. While the range of commodity prices generated by the Monte Carlo simulation impacts the probability of default calculations, the latter are also sensitive to the pathway scenario's product portfolio diversity. The FPH scenario is unique in that it yields equal volumes of gasoline and diesel fuel and the largest amount of electricity. The EH and IB scenarios stand in sharp contrast to the FPH scenario, generating only a single liquid fuel product in the form of ethanol and butanol, respectively, and utilizing a single feedstock in the form of stover (the three thermochemical scenarios all utilize both stover and natural gas as inputs). The probability of default results indirectly affect the NPV results in turn, as the related ICR determines the cost of debt of each pathway scenario. In other words, a high initial probability of default results in a low initial ICR, which increases the cost of debt and thereby increases the probability of default still further. NPV is therefore an important measure of economic feasibility but not the only one that should be considered in TEAs, as a cellulosic biofuel pathway with a high NPV and high probability of default is less likely to contribute to the RFS2 than a less profitable pathway that is able to avoid default via product portfolio diversity.

The results of this analysis suggest that government subsidization of cellulosic biofuels production and/or consumption will be required if corn stover is to be a viable feedstock under the RFS2. None of the five pathway scenarios considered achieve a positive

average 20-year NPV. Of equal importance are the very high probabilities of default

calculated for the HTG & FTS, LTG & FTS, EH, and IB pathway scenarios during their first

decade of operations, which indicate that they will be unlikely to contribute to the RFS2 for

even a majority of their 20-year lifespans. In reality it will be difficult for pathways

presenting investors with the near-certainty of default to acquire the necessary capital

investment to begin production in the first place. While government subsidies have the

potential to reduce the likelihood of default for the cellulosic biofuel pathways considered

and improve the ability of stover to contribute to the RFS2 as a cellulosic feedstock, most of

the stover pathways considered by this analysis are unlikely to achieve economic feasibility

in their absence.

3.5.   Sensitivity analysis

Two sensitivity analyses are completed to determine the influence of the analysis

assumptions on its results. The first sensitivity analysis is performed via Crystal Ball's

Tornado Chart® tool to quantify the sensitivity of the ICR of each pathway scenario to each

commodity. A testing range between the 20th and 80th percentile of each commodity price

distribution in the first month of the analysis (sensitivity steadily declines which each

subsequent month) is employed to calculate a range of ICR values. The results of the

sensitivity analysis are presented in Table 3.8.

Table 3.8. Sensitivity of ICR to commodity prices

Commodity	S1	S2	S3	S4	S5
	ICR range				
Diesel fuel	0.075	0.071	0.190	0.000	0.000
Electricity	0.004	0.006	0.019	0.013	0.012
Gasoline	0.047	0.043	0.241	0.230	0.181
Natural gas	0.001	0.001	0.067	0.000	0.000
Stover	0.069	0.084	0.168	0.126	0.105

The ICRs of all five of the pathway scenarios are most sensitive to changes in the price of the pathway's primary transportation fuel output. The two gasification and FTS scenarios produce twice as much diesel fuel as gasoline by volume and their respective ICRs are much more sensitive to changes in the price of the former than of the latter as a result. The HTG & FTS scenario is more sensitive to the price of diesel fuel than to the other commodities. The LTG & FTS scenario is most sensitive to the stover cost, however, due to its lower fuel yield relative to the HTG & FTS scenario. The EH and IB scenarios produce no diesel fuel (or a substitute) and are most sensitive to the price of gasoline as a result. While the FPH scenario produces equal volumes of gasoline and diesel fuel it is more sensitive to the price of the former due to the broader range of gasoline prices employed in the Monte Carlo simulation (see Table 3.**3**). The ICRs of the FPH, EH, and IB scenarios are all very sensitive to the stover cost, although this is not as important as the transportation fuel price due to the relatively high fuel yields attained by each of the scenarios. All of the pathway scenario ICRs are only weakly sensitive to the prices of electricity, indicating that there is both relatively value to be attained via electricity generation and low electricity price uncertainty. Only the FPH pathway scenario is sensitive to the price of natural gas, and even this is weak relative to the scenario's sensitivity to transportation fuel prices and the cost of stover. Of the commodities considered by this analysis, then, only the primary feedstock and products can be expected to have a substantial impact on pathway ICR.

The second sensitivity analysis employs Monte Carlo simulation to calculate 20-year NPVs and 10-year probabilities of default for each pathway scenario using the identical financial assumptions of a 100% debt/equity ratio, 10% IRR, 7.5% interest rate, and working

capital equal to 15% of fixed capital investment (FCI). Employment of these identical

financial assumptions generates NPVs and probabilities of default that are in some cases

substantially higher and lower, respectively, than under the pathway-specific assumptions

based on unique pathway scenario cash flows (see Table 3.9). The magnitude of this

difference varies by pathway scenario, however. The probabilities of default for the HTG &

FTS, LTG & FTS, EH, and IB scenarios are only marginally lower (if at all) under the

identical financial assumptions, due to the negative returns under both sets of assumptions.

The 20-year NPVs of the four scenarios increase by as much as $282 million but remain too

low to generate low default probabilities. The exception to this is the FPH scenario, for

which a 10-year default probability of 45.3% is calculated under the identical financial

assumptions. The reason for the pathway scenario's sharp reduction to probability of default

is the corresponding increase to a positive NPV under the identical financial assumptions.

Similar results could be expected for the other pathways were their 20-year NPVs not so low

to begin with. The results of the second sensitivity analysis indicate that the use of identical

financial assumptions in TEAs of cellulosic biofuel pathways generate results that overstate

their economic feasibility, although the magnitude of this overstatement varies by pathway.

Table 3.9. Sensitivity of results to financial assumptions

	Pathway-specific financial assumptions		Identical financial assumptions	
Scenario	Mean NPV ($MM)	Default prob.	Mean NPV ($MM)	Default prob.
S1	-$749.4	100%	-$467.0	98.5%
S2	-$742.9	100%	-$543.2	100%
S3	-$134.7	80.5%	$133.1	45.3%
S4	-$773.9	100%	-$687.0	100%
S5	-$679.0	100%	-$499.0	99.4%

3.6. Conclusion

This paper quantifies the 20-year net present value (NPV) and 10-year probability of default for five stover-based cellulosic biofuel pathway scenarios using a discounted cash flow rate of return spreadsheet. Unlike previous techno-economic analyses (TEA), this paper calculates pathway-specific costs of debt and equity for each pathway scenario based on industry cash flows and scenarios' respective cash flows. Feedstock requirements, output yields, product portfolios, and capital costs are derived from recent TEAs in the refereed literature. Input costs and output prices for the five energy commodities covered are calculated stochastically via Monte Carlo simulation as a random walk with drift, with the drift based on the 20-year price projections in the U.S. Energy Information Administration's Annual Energy Outlook. Finally, two sensitivity analyses are employed to quantify the sensitivity of the interest coverage ratio (ICR) to the commodity prices and of the NPV and probability of default calculations to the type of financial assumptions made.

This paper calculates negative mean NPVs for all of the pathway scenarios. Furthermore, it calculates very high (100%) probabilities of default for all of the scenarios except the fast pyrolysis and hydroprocessing scenario. The wide range of stochastic price paths simulated by the analysis results in large 20-year NPV standard deviations for all of the pathway scenarios. The first sensitivity analysis identifies the ICR as being most sensitive to the transportation fuel prices and feedstock costs, although the magnitude and ranking of this sensitivity varies by pathway. Finally, the second sensitivity analysis finds that the use of arbitrary financial assumptions across all scenarios results in the overestimation of 20-year NPVs and underestimation of 10-year default probabilities.

3.7. Acknowledgements

CHAPTER 4. QUANTIFYING THE ECONOMIC COMPETITIVENESS OF INITIAL U.S. CELLULOSIC BIOFUEL PATHWAYS

A paper to be submitted for publication in an international refereed journal

Tristan R. Brown[1] and Mark M. Wright[2]

4.2.   Abstract

This paper calculates 20-year net present values (NPV) and 10-year probabilities of default for six cellulosic biofuel pathways under eight location scenarios. Each location scenario resembles one of the nine commercial-scale cellulosic biofuel projects planned in the U.S. at the end of 2012 and accounts for location-specific factors such as capital costs, feedstock type, feedstock costs, energy commodity prices, and state corporate income tax rates. Negative 20-year NPVs and low probabilities of positive NPVs are calculated for seven of the eight location scenarios. Very high (>98%) probabilities of default are also calculated for seven of the eight location scenarios, while every scenario is calculated to have a probability of default above 50% over 10 years.

4.3.   Introduction

The Energy Independence and Security Act of 2007 (EISA) mandates the consumption of increasing volumes of biofuels derived from lignocellulosic biomass ("cellulosic biofuels"). The mandate, as part of the larger revised Renewable Fuel Standard (RFS2), requires this biofuel category to become the largest biofuel by volume in 2022 (2). Initial optimism regarding the economic and technical feasibility of cellulosic biofuel pathways quickly flagged as production routinely failed to make its mandated appearance

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(130,131). The Environmental Protection Agency (EPA) oversees the RFS2 and has greatly

reduced the mandate's original volumes for each of the last four years due to a lack of

cellulosic biofuel capacity (2). Despite these modifications, the annual adjusted mandates

have consistently exceeded the supply of cellulosic biofuels. In 2010 and 2011 the EPA

adjusted the original 100 million gallon and 250 million gallon cellulosic biofuel mandates to

6.5 million gallons and 6.6 million gallons, respectively. The 2012 mandate called for 500

million gallons but was reduced by the EPA to 10.5 million gallons. Similarly, the original

2013 mandate of 1000 million gallons of cellulosic biofuel consumption was later reduced to

14 million gallons.

Despite these adjustments by the EPA, actual cellulosic biofuel consumption has

continued to fall far short of the adjusted volumes due to a lack of production. No

consumption occurred in 2010 and 2011 (11) while the actual volumes for 2012 and 2013

were 99% and 97% below the adjusted mandates, respectively (5,12). In 2013 a U.S.

appellate court ruled that the methodology on which the EPA was basing its annual adjusted

volumes was weighted toward overproduction and therefore flawed (13). The EPA's position

is that skewing its projections toward overproduction improves the economic feasibility of

cellulosic biofuel pathways since the value of the mandate's flexible subsidy component

(Renewable Identification Numbers, or RINs) increases when actual production falls short of

the volumetric mandate (132). This approach has prompted multiple lawsuits from the

petroleum industry, which bears the cost of the flexible subsidy, against the EPA, as well as

Congressional proposals to eliminate the RFS2's so-called "phantom fuels" mandate (133).

The debate over the EPA's projections has been driven by the fact that the RFS2 has

not incentivized nearly enough capacity investment in cellulosic biofuel pathways to meet the

mandated consumption volumes. The RFS2 mandates the annual purchase of cellulosic

biofuel by "obligated blenders", generally petroleum refiners. It encourages production of the

corresponding biofuel via RINs, which are a flexible subsidy payment from obligated

blenders to cellulosic biofuel producers and non-obligated blenders for every gallon of

cellulosic biofuel that is blended with gasoline or diesel fuel for retail. In order to prevent the

subsidization of windfall profits, the core RIN value operates as a function of the cellulosic

biofuel's production cost and the market price of petroleum; the RIN value increases when

the biofuel's production cost increases and decreases when petroleum's market value

increases, so long as total production does not exceed the volumetric mandate (2,20). This

flexible subsidy has worked well for the other biofuel categories under the RFS2 due to the

existence of significant capacity at the time of the program's implementation. It has had little

success encouraging cellulosic biofuel production and capacity investment to date, however,

because the core RIN value can only be calculated when production exists and production

costs are well-known. Since no cellulosic biofuel production occurred in 2010 and 2011 and

only minimal volumes were produced in 2012 and 2013, however, neither cellulosic biofuel

production costs nor RIN values are well-known.

The lack of an established RIN price has discouraged investment in cellulosic biofuel

capacity by creating uncertainty as to the ability of cellulosic biofuel pathways to compete

with fossil fuel pathways, particularly petroleum refining. Efforts to estimate future cellulosic

biofuel RIN values have been hampered by the diversity of pathways qualifying for the

cellulosic biofuels mandate, with each possessing a unique set of technical and economic

specifications. One comparative techno-economic analysis (TEA) of the three pathways

closest to commercialization calculates minimum fuel selling prices (MFSP) varying from a

low of $2/gallons gasoline-eq. (gge) to a high of $5.50/gge (29–31,93). A subsequent attempt

by the National Research Council (NRC) to calculate the necessary total cost of cellulosic

biofuel subsidization under the RFS2 as the difference between these results and assumed

transportation fuel prices presents a range of $31 billion due to this uncertainty (99). At the

beginning of 2013 there were at least six different pathways expected to achieve commercial-

scale (>20 million gallons per year) production by the beginning of 2015 (27) as opposed to

the three considered by the National Research Council, suggesting that the actual subsidy

cost range could be larger still.

Further complicating efforts to quantify future cellulosic biofuel RIN prices is the

expected regional variation in production costs for individual pathways. A number of

variables to which the economic competitiveness of cellulosic biofuel pathways is sensitive,

such as capital costs, feedstock costs, and product market prices, vary substantially across

regions. A recent analysis calculates that the 20-year net present value (NPV) of a 2000

metric ton (MT)/day fast pyrolysis and hydroprocessing (FPH) facility varies from -$79.5

MM to $165.5 MM depending on the U.S. state in which it is located (32). Potential investors

and creditors are unlikely to provide the capital necessary for construction of a commercial-

scale cellulosic biofuel facility unless an adequate return on capital is likely to be achieved

and this will not be possible in all potential locations absent the provision of government

support. Many TEAs of cellulosic biofuel pathways published in the refereed literature limit

capital cost calculations to a U.S. Gulf Coast basis due to the heavy concentration of fossil

fuel-related chemical engineering projects in the region. Aspen Capital Cost Estimator® and

the CHEMCAD® software suite are two programs that are commonly employed for the

techno-economic modeling and capital cost estimation of cellulosic biofuel pathways

(29,72,74,85,93,134). Sufficient concentrations of lignocellulosic biomass to supply commercial-scale facilities are available in U.S. regions outside of the Gulf Coast such as the Midwest (135), however, and capital cost factors vary across these regions due to differences in infrastructure, equipment and materials availability, labor costs, weather, and seismic activity (136).

Region-sensitive factors that also influence the calculated economic competitiveness of cellulosic biofuel facilities in addition to capital costs are feedstock costs, transportation fuel prices (excluding state fuel excise taxes), and state corporate income tax rates (32). Feedstock type is region-specific due to differences in growing conditions, ecosystems, and agricultural practices across regions. For example, the U.S. Midwest is expected to be a major future supplier of corn stover to cellulosic biofuel producers due to the large amounts of corn already grown in the region. The U.S. Southeast, on the other hand, is already a major provider of softwoods to the paper and pulp industry and is expected to contribute forestry feedstock to the cellulosic biofuel sector (26). Furthermore, differences in the level of market development for each feedstock affect the level of uncertainty regarding the price of each. While detailed market prices are widely available for softwoods in major timber-producing states, the absence of stover collection on a commercial-scale at the time of writing makes estimated stover costs and market prices highly uncertain. The assumed feedstock cost for a Midwest biorefinery utilizing stover is much less certain than that for a Gulf Coast counterpart utilizing softwood, other things being equal.

Finally, commodity price volatility and uncertainty have both been shown to impact the 20-year NPVs of cellulosic biofuel pathways (104). Commodity prices, especially energy prices, exhibit high volatility and in turn increase the cash flow volatility of the facilities that

employ them as inputs (natural gas) and/or outputs (transportation fuels). High cash flow volatility increases the probability that a producer's revenue will be temporarily insufficient to meet its periodic debt payments, in the event of which a default occurs and continued future operations at the facility are unlikely. Accounting for this anticipated future price volatility in TEAs of cellulosic biofuel pathways is important as it generates a range of possible financial results with corresponding probabilities rather than a single result that is erroneously believed to be known with complete certainty (104,137). Accounting for uncertainty in price projections is important for the same reason, as projections are not known with complete certainty even when price volatility is not considered.

While U.S. cellulosic biofuel commercialization to date has fallen well below the volume necessary to meet the initial mandates of the RFS2, nine facilities with a combined 323 million gallons per year (MMGY) of capacity on an ethanol-equivalent basis were expected at the beginning of 2013 to be in operation within two years (27). The announced locations of these facilities are in eight different states, with two in Iowa and one apiece in Louisiana, Kansas, Michigan, Mississippi, North Carolina, Oregon, and Tennessee. Efforts such as that by the NRC to calculate the financial returns of these facilities and subsequent subsidization costs of the RFS2 on the basis of Gulf Coast capital costs, national commodity prices, and identical financial assumptions do not reflect this diversity of cellulosic biofuel facility pathways and locations. Accounting for this regional diversity can be expected to provide more realistic TEA results of the pathway facilities modeled and a more accurate estimate of the RFS2's short-term subsidization costs than would be generated without its consideration.

The objective of this analysis is to quantify the economic competiveness of the six

pathways to be employed by the nine facilities expected to be in operation in 2015, with each

facility serving as an individual location scenario, within their specific state locations and

under price uncertainty. Eight location scenarios are developed (two of the nine facilities are

expected to employ the same pathway in the same location and only one is considered here as

a result) and each scenario is based on a recent cellulosic biofuel pathway TEA from the

open literature for the appropriate scenario (although in two cases the TEA is for a similar

but not identical pathway).

4.3.1. Methodology

4.3.2. Scenario selection

Eight location scenarios are developed to represent the nine commercial-scale

cellulosic biofuel facilities (defined here as those with annual biofuel capacities exceeding 20

MMGY) that are expected to be in operation in the U.S. by 2015. Each scenario broadly

resembles one of the nine commercial-scale cellulosic biofuel facilities that is expected to be

operating by the beginning of 2015 (27). While the pathways considered are selected based

on their U.S. commercialization status, the pathways for which TEAs are available in the

open literature are not always identical to those that are being commercialized. For example,

Scenario 3 considers the production of ethanol from lignocellulosic biomass via gasification,

methanol synthesis to acetic acid, and acetic acid hydrogenation processes. While Zeachem is

building a commercial-scale facility in Oregon that will employ a similar process for the

conversion of acetic acid to ethanol, the company's acetic acid is produced via biomass dilute

acid hydrolysis and fermentation of the resulting substrate (138). Since there are no TEAs of

that specific biochemical pathway for the production of acetic acid in the literature, Scenario

3 considers the related thermochemical pathway (71). Similarly, Scenario 1 is based on a

TEA of a mild catalytic pyrolysis process that is similar but not identical to the pathway

employed by KiOR, which employs a proprietary catalytic pyrolysis process. Figure 4.1

presents the steps employed by this analysis for developing each location scenario. Table 4.1

presents the pathway and relevant operating assumptions employed for each location

scenario (ethanol output is presented on a gasoline-equivalent basis).
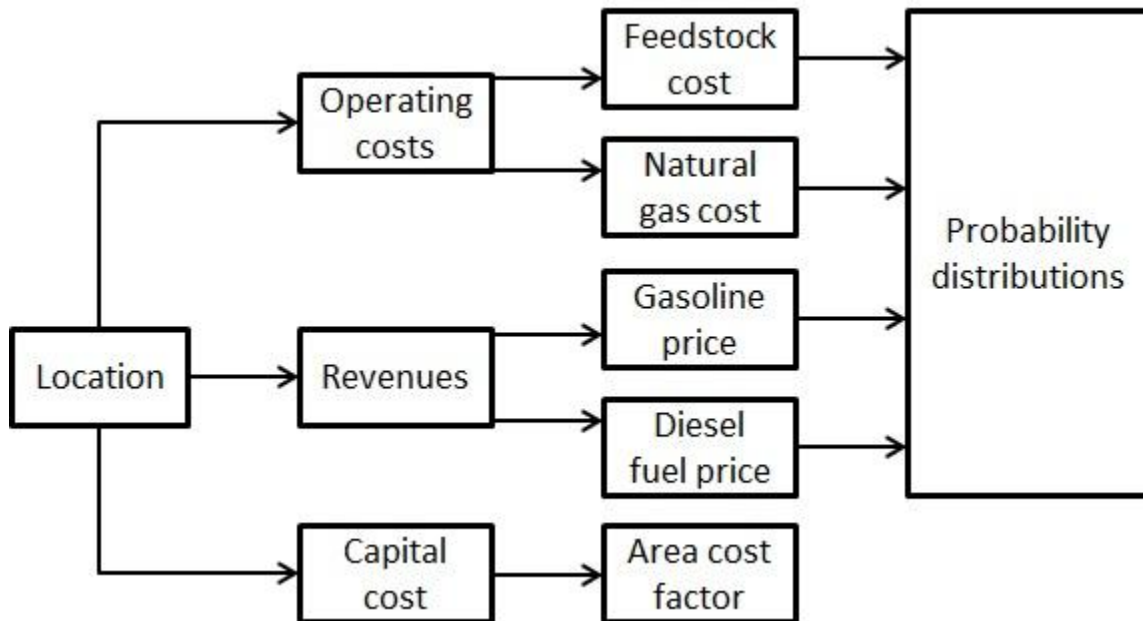
Figure 4.1. Methodology employed by analysis. Note that corporate income taxes are not included in flowchart for simplicity.

Table 4.1. Location scenario details.

Location scenario	Pathway	Location	Gasoline-eq. output (MMGY)	Diesel fuel output (MMGY)	Net electricity output (MW)	Literature feedstock	Assumed feedstock type for cost
S1 (120)	Mild catalytic pyrolysis & hydroprocessing to hydrocarbons	MS	26.3	12.3	33.7	Hybrid poplar	Short-rotation woody crops
S2 (139)	Consolidated bioprocessing to ethanol	MI	23.1	0	26.8	Corn stover	Forest residue
S3 (71)	Direct-heat gasification & acetic acid synthesis to ethanol	OR	117.3	0	-14.2	Wood chips	Forest residue
S4 (30)	Enzymatic hydrolysis to ethanol	KS	35.6	0	25.8	Corn stover	Corn stover
S5 (30)	Enzymatic hydrolysis to ethanol	IA	35.6	0	25.8	Corn stover	Corn stover
S6 (30)	Enzymatic hydrolysis to ethanol	NC	35.6	0	25.8	Corn stover	Corn stover
S7 (29)	High-temp gasification & F-T synthesis to hydrocarbons	TN	12.9	25.8	13.8	Corn stover	Forest residue
S8 (74)	Gasification & MTG synthesis to hydrocarbons	LA	42.5	0	0	Poplar wood	Forest residue

4.3.3. Feedstock cost

The lignocellulosic feedstock assumption for each location scenario is made within the constraints of data availability in the open literature. The TEAs used to develop each location scenario are based on a single lignocellulosic feedstock each. Frequently the assumed type of lignocellulosic feedstock in a pathway TEA is not always the same as that being employed by a commercial-scale counterpart biorefinery in practice. Rather than exclude an otherwise-suitable pathway from this analysis whenever such a difference occurs, it is instead assumed that the pathway TEA's feedstock is employed by the relevant location scenario from a processing standpoint in terms of calculating capital costs and process yields. However, the feedstock price most likely to be encountered in practice by the relevant pathway based on current commercialization trends is used in the discounted cash flow rate of return (DCFROR) analysis. Such an assumption is made for Scenarios 2 and 7, which utilize pathway TEAs in which stover is the pathway feedstock but assume that the stover is made available at the cost of forest residue feedstock (see Table 4.1). It should be noted that feedstock type can be expected to influence compositions and yields of the final products, although at this time there is not a clear correlation between individual lignocellulosic feedstocks and pathway yields; see Elliott et al. 2009 (140) for a thermochemical pathway example. Finally, all of the location scenarios considered by this analysis are within states that have been previously identified as having sufficient feedstock to supply a biorefinery with feedstock demand of up to 2000 MT/day (32).

The NRC's calculation of the costs of cellulosic biofuel pathways employs the Biofuel Breakeven Model (BioBreak) to determine lignocellulosic biomass producers' willing to accept (WTA) price for multiple feedstocks and U.S. regions (99). The BioBreak

model calculates the WTA prices on the assumption of a $120/bbl crude petroleum price

(2011 dollars), which is close to the Energy Information Administration's (EIA) 2013

Annual Energy Outlook (AEO) average 20-year price projection for West Texas Intermediate

(WTI) petroleum of $109.45/bbl (19). This analysis utilizes the BioBreak model's WTA

price (adjusted to a 2011 cost basis) results under the $120/bbl petroleum price assumption as

the feedstock prices for each of the respective location scenarios (see Table 4.2). Since

Scenarios 2, 7, and 8 assume the use of feedstocks that are not utilized by their real-life

counterparts, however, the feedstock costs most likely to be incurred by the latter based on

the BioBreak results are employed in this analysis.

Table 4.2. Location scenario market conditions. Price ranges based on projections from 2013 to 2032.

Location scenario and source	Electricity price, 2013-2032 ($/kWh)	Natural gas price, 2013-2032 ($/MMBTU)	Gasoline price ex-tax, 2013-2032 ($/gal)	Diesel fuel price ex-tax, 2013-2032 ($/gal)	Feedstock cost ($/dry MT)	State corp. tax rate (%)	Location capital cost factor	Adj. TPI (MM 2011 US$)
S1 (120)	0.055-0.056	4.74-7.32	3.05-3.48	3.16-3.98	$93	5.0	0.99	452.0
S2 (139)	0.065-0.071	5.24-7.63	3.06-3.51	3.16-4.03	$93	6.0	1.28	458.2
S3 (71)	0.074-0.076	5.30-7.98	3.22-3.82	3.19-4.33	$106	7.0	1.28	1,001.7
S4 (30)	0.058-0.064	4.45-7.05	3.00-3.48	3.13-4.00	$110	7.0	1.06	431.8
S5 (30)	0.058-0.064	4.45-7.05	3.00-3.48	3.13-4.00	$110	12.0	1.15	470.2
S6 (30)	0.063-0.068	5.30-7.64	3.05-3.56	3.17-4.08	$119	6.9	0.94	383.8
S7 (29)	0.055-0.056	4.74-7.32	3.05-3.48	3.16-3.98	$93	6.5	1.01	665.1
S8 (74)	0.051-0.068	2.94-5.37	3.01-3.46	3.13-3.96	$93	8.0	1.00	216.5

4.3.4. Location capital cost factor

Facility location also impacts its total capital cost. Capital cost estimates generated by process engineering software are commonly reported in the open literature on a U.S. Gulf Coast basis, as chemical engineering equipment is frequently sourced in that region due to its high concentration of petroleum refineries and transport hubs. Constructing the same biorefinery in another region incurs region-specific factors that affect its capital costs, including differences in equipment transport, equipment availability, local weather, seismic activity, and wages (136). A previous study reviews the various regional construction cost indices that have been created for the purpose of calculating capital costs for a given location and baseline (32). These include the Department of Defense (DOD) United Facilities Criteria (136), the Richardson International Construction Factors Manual[TM] (141), and the ENR 20-city Construction Cost Index (142).

This analysis utilizes area cost factors published by the DOD due to their inclusion of hundreds of U.S. locations, both urban and rural (136). The Richardson International Construction Factors Manual[TM] and ENR 20-city Construction Cost Index are limited to urban costs that are unlikely to be encountered by bioenergy facilities due to the high costs that would be incurred by transporting biomass feedstock from rural production areas (75). The DOD's area cost factors are based on local costs for a basket of eight labor activities, 17 construction materials, and four equipment items. State average factors are attained from the index for each location scenario and adjusted to place them on the same basis by using the average state area cost factor for Louisiana as unity. The adjusted average area cost factors for each state are then applied to the unadjusted total project investment (TPI) of each relevant location scenario to calculate an adjusted TPI (see Table 4.1). This adjusted TPI is

employed in the discounted cash flow rate of return (DCFROR) analysis as the biorefinery capital cost.

4.3.5. State corporate income tax rate

While the U.S. federal corporate income tax rate for corporations is uniform with a top bracket rate of 35%, business entities must also pay corporate income tax at the state level. The top rate varies by state, from 12% in Iowa to zero in South Dakota (143). Each location scenario in this analysis accounts for both the 35% federal rate as well as the respective state corporate income tax rate as part of the DCFROR analysis. This analysis does not account for unique incentives, such as tax credits and low-interest loans that some states provide to specific enterprises operating within their borders.

4.3.6. Energy commodity prices

The market prices of gasoline and diesel fuel vary on a regional basis even after state-level differences in fuel excise taxes are accounted for (92,144). Similar price differences are witnessed for the market prices of electricity and natural gas as well (see Table 4.2). This analysis assumes that each facility simulated by the respective location scenario purchases from and sells into its local market as defined by the EIA's Petroleum Administration for Defense Districts (PADD) region, as opposed to importing or exporting from other PADD region markets and incurring transportation costs in the process. These differences in energy commodity prices therefore have disparate impacts on the economic competitiveness of each location scenario.

The EIA publishes long-term price projections for each of the energy commodities listed in Table 4.2 as part of its AEO (19). Separate price projections are also made available by the EIA for each of the PADD regions. This analysis assumes that each cellulosic biofuel

facility will be operational for 20 years and it employs the EIA's projected prices for the years 2013-2032 to quantify the competitiveness of each location scenario. Furthermore, each location scenario uses the price projections for the relevant PADD scenario (e.g., Scenarios 4 and 5 employ the same projected energy commodity prices since Kansas and Iowa are both in the Midwest PADD region). The price of hydrogen is treated as a function of the natural gas price under the assumption that the former is produced via steam methane reforming of the latter (80).

4.3.7. Uncertainty analysis

This analysis employs Monte Carlo simulations to calculate both a 20-year NPV probability distribution and a 10-year (i.e., the assumed loan period) probability of default for each location scenario. The NPV probability distribution also makes it possible to derive the probability that each location scenario's 20-year NPV is greater than zero. This analysis employs the methodology developed by Brown and Wright (145) in previous work to conduct the uncertainty analysis, which consists of the following steps: (1) historical data on monthly energy commodity price changes is fit to probability distributions; (2) 20-year cash flows are deterministically simulated to calculate interest coverage ratios (ICR) for each location scenario; (3) costs of debt and equity are calculated for each location scenario as a function of their ICRs and industry betas, respectively; and (5) 20-year NPV distributions and 10-year probabilities of default are calculated for each location scenario. The methodology for calculating costs of debt and equity is covered in detail elsewhere (117,118,145) and therefore not repeated here.

The Monte Carlo simulation methodology employed in this analysis differs from previous work (104,145) in that it develops and employs energy commodity price

distributions that are unique to each location scenario. The probability distributions are developed based on the monthly price changes from January 2001 to December 2013 for natural gas, gasoline, diesel fuel, and LPG (the latter being a byproduct yielded by Scenario 8) in each location scenario's PADD region (146–148). EIA data on the historical gasoline and diesel fuel retail prices for each PADD region is adjusted to an ex-tax basis by excluding the federal and state fuel excise taxes for the respective location scenarios (92). The probability distribution for forest residue price changes for the scenarios employing that feedstock is derived from quarterly price data from January 1996 to December 2013 for Louisiana pine pulpwood (149). This probability distribution is applied to all of the location scenarios in which forestry residue is the assumed feedstock due to a lack of sufficient price data for other states. There is no historical data on corn stover prices from which to develop probability distributions due to the lack of an historical stover market. This analysis therefore uses historical monthly corn price changes (116) as a proxy from which to derive the probability distribution for stover due to stover being a byproduct of corn production. This analysis makes the assumption that the factors causing corn prices to increase (e.g., drought, late harvests, etc.) will also cause stover prices to increase, and vice versa. Finally, the Consumer Price Index is used to adjust all prices to a 2011 cost year basis prior to calculating their monthly changes (76). The probability distributions and monthly price change ranges within a 95% confidence interval for each energy commodity are presented in Table 4.3. While almost all of the energy commodity price changes are determined according to Anderson-Darling goodness-of-fit test results to best fit to logistic distributions (with the exception of natural gas under Scenario 2), the range of monthly price changes is found to differ according to energy commodity and location scenario.

Table 4.3. Probability distribution function for monthly change of each commodity price

Scenario	Commodity	Distribution	Monthly price change range (95% CI)
S1	Natural gas	Logistic	-18.1% – 18.5%
	Gasoline	Logistic	-18.3% - 18.4%
	Diesel fuel	Logistic	-10.9% - 11.1%
	Feedstock[b]	Logistic	-22.0% - 22.0%
S2	Natural gas	Student's t	-12.2% - 12.5%
	Gasoline	Logistic	-18.3% - 18.4%
	Diesel fuel	Logistic	-14.6% - 14.8%
	Feedstock[b]	Logistic	-22.0% - 22.0%
S3	Natural gas	Logistic	-10.8% - 11.2%
	Gasoline	Logistic	-14.6% - 14.7%
	Diesel fuel	Logistic	-14.6% - 14.8%
	Feedstock[b]	Logistic	-22.0% - 22.0%
S4	Natural gas	Logistic	-25.5% - 25.8%
	Gasoline	Logistic	-18.3% - 18.4%
	Diesel fuel	Logistic	-10.9% - 11.1%
	Feedstock[a]	Logistic	-11.0% - 11.0%
S5	Natural gas	Logistic	-25.5% - 25.9%
	Gasoline	Logistic	-18.3% - 18.4%
	Diesel fuel	Logistic	-10.9% - 11.1%
	Feedstock[a]	Logistic	-11.0% - 11.0%
S6	Natural gas	Logistic	-18.2% - 18.5%
	Gasoline	Logistic	-14.6% - 14.7%
	Diesel fuel	Logistic	-10.9% - 11.1%
	Feedstock[a]	Logistic	-11.0% - 11.0%
S7	Natural gas	Logistic	-18.1% - 18.5%
	Gasoline	Logistic	-18.3% - 18.4%
	Diesel fuel	Logistic	-10.9% - 11.1%
	Feedstock[b]	Logistic	-22.0% - 22.0%
S8	Natural gas	Logistic	-25.4% - 25.9%
	Gasoline	Logistic	-14.6% - 14.7%
	Diesel fuel	Logistic	-10.9% - 11.1%
	LPG	Logistic	-20.7% - 20.9%
	Feedstock[b]	Logistic	-22.0% - 22.0%

[a]Distribution based on historical corn prices due to lack of a developed stover market

[b]Distribution based on historical Louisiana pine pulpwood prices due to lack of data from other states

Correlations between commodity prices are also identified and derived from the historical energy commodity prices for each PADD region included in this analysis. Strong correlations (>0.5) are identified via Spearman's correlation coefficient (150) for the monthly price changes of gasoline and diesel fuel, natural gas and LPG, and diesel fuel and corn for each PADD region. The prices of some energy commodities have been correlated historically due to their use of a common feedstock (e.g., gasoline and diesel fuel) or use as a similar product (e.g., natural gas and LPG). These correlations are included when performing the Monte Carlo simulations for the respective energy commodity price changes so as to prevent unrealistic price movements between energy commodity prices that have been historically correlated.

Future energy commodity prices are simulated via Monte Carlo simulation as a function of the EIA's price projections and the probability distributions based on historical monthly price changes. All of the simulated energy commodity prices with the exception of feedstock are assumed to follow a random walk with drift, where the drift is set according to the 20-year monthly price increase required for each price to reach the EIA's respective price projection for 2032. Feedstock price instead follows a random walk since the EIA does not provide 20-year price projections for stover and softwood. The monthly price changes are truncated to include only those falling within a 95% confidence interval (CI) so as to eliminate ahistorical extreme price movements. Crystal Ball® software is used to generate 10,000 random monthly price changes per energy commodity, with the price in one month equaling the previous month's price plus the random change, as presented by Esty (1999) (129):

$$P_t = P_{t-1}(1 + \text{random change})$$

The amount of each random change is derived from the fitted probability distributions described above. When aggregated, the monthly price changes calculated by the Monte Carlo simulation yield 10,000 random price paths for each energy commodity and each location scenario over the 20-year facility life. These random price paths are incorporated into the DCFROR spreadsheet to calculate interest coverage ratios (ICR) for each location scenario via the methodology described in previous work (145). The ICRs are continuously adjusted until the cost of debt calculations converge, at which point the appropriate interest rate is incorporated into the location scenario (see Table 4.4) (117). The cost of equity is assumed to be 14.3% for all of the location scenarios based on the calculations by Brown and Wright (2014) (145).

Table 4.4. Cost of debt results for each location scenario

Scenario	Mean interest coverage ratio	Cost of debt
S1	0.12	18.7%
S2	-1.26	18.7%
S3	-0.21	18.7%
S4	-0.98	18.7%
S5	-0.96	18.7%
S6	-1.06	18.7%
S7	-0.28	18.7%
S8	1.74	9.0%

10-year probabilities of default are calculated stochastically as the probability that the mean minimum debt coverage service ratio (DCSR) of a location scenario is less than 1.0. The methodology for calculating DCSR is covered elsewhere (129,145) and not repeated here. This analysis increases the capital cost of each location scenario in the form of cash working capital so that the DSCR in the first six months of operations is equal to the greater of 1.0 or the mean DCSR over the first 10 years of operations. This adjustment is made to prevent the minimum DSCR from falling below 1.0 (and generating a default) during three

years of construction and the six-month start-up process, the latter period during which

revenues are assumed to be only 50% of normal. The percentage of working capital relative

to each location scenario's capital cost is therefore a function of both its cost of debt and its

total capital cost, although this analysis assumes that it does not fall below 15%, which is the

value commonly assumed in the TEAs used to develop the eight location scenarios.

4.4.   Results

20-year NPVs and 10-year probabilities of default are stochastically calculated for six

cellulosic biofuel pathways under a total of eight location scenarios. Seven of the eight

scenarios have very low probabilities of achieving a 20-year NPV that is greater than zero

while only Scenario 8 has a greater than 50% probability of achieving the threshold (see

Table 4.5). The other seven scenarios all have probabilities of below 5% of achieving the

threshold. One of the main drivers of negative NPVs is the high costs of debt incurred by

most of the location scenarios (see Table 4.4). These costs necessitate high amounts (both in

absolute terms and relative to capital costs) of working capital to provide Scenarios 1-7 with

sufficient DSCRs during their construction and start-up periods. The working capital

contributes to each scenario's total liabilities, however, causing interest payments to rise and

NPV to fall. With the exception of Scenario 8, none of the scenarios achieve positive 20-year

NPVs in the absence of sustained very low input costs and very high output market prices.

Table 4.5. Location scenario mean 20-year NPVs and 10-year probabilities of default.

Scenario	Mean NPV ($MM)	Prob. NPV>0	Default prob.
S1	-588.0	4.6%	98.9%
S2	-1,401.1	0.1%	100.0%
S3	-1,738.3	4.6%	98.7%
S4	-1,025.3	1.8%	100.0%

97

Table 4.5 continued			
Scenario	Mean NPV ($MM)	Prob. NPV>0	Default prob.
S5	-1,093.0	1.1%	100.0%
S6	-940.1	0.7%	100.0%
S7	-1,022.9	0.2%	100.0%
S8	33.0	54.2%	61.1%

Scenarios 1-7 all have very high (>98%) 10-year default probabilities (see Table 4.5). The majority of the scenarios have a 100% probability of defaulting during the first decade of operations, while even Scenario 8 has a greater than even probability of doing so. As with the NPV calculations, the 10-year default probabilities are driven by the high costs of debt incurred by the majority of the location scenarios relative to their probable revenues. A negative feedback loop is witnessed in Scenarios 1-7 in which high capital costs incur high costs of debt, necessitating higher capital costs to keep the DSCR above 1.0 during the construction and start-up periods. While this increase to absolute debt costs ultimately causes the default probability to approach 100%, it is necessary if default is not to occur prior to the commencement of full operations.

The results of this analysis indicate that the first several cellulosic biofuel pathways to be commercialized within the U.S. will not be competitive with fossil fuels on an unsubsidized basis. Indeed, it is more likely than not that the first facilities to employ these pathways will default prior to achieving a decade of continuous operations unless supported by the government. Faced with such low probabilities of success and substantial regulatory uncertainty regarding the future shape and existence of the RFS2, it should come as little surprise that U.S. cellulosic biofuel capacity investment to date has fallen well short of its mandated volume. Furthermore, given the historically-low interest rates and relatively high petroleum prices that have prevailed in the U.S. over the last five years, it is unlikely that a

sudden change in macroeconomic conditions will improve the future competitiveness of the pathways included in this analysis. Future research should focus on reducing pathway costs of capital by improving product yields and, perhaps more importantly, diversifying product portfolios so as to reduce debt costs by decreasing the sensitivity of pathway cash flows to a single energy commodity price.

4.5. Conclusion

This paper quantifies the 20-year net present value (NPV) and 10-year probability of default for six cellulosic biofuel pathways under eight location scenarios. Each location scenario is designed to resemble one of the commercial-scale cellulosic biofuel projects planned within the U.S. at the end of 2012 and accounts for location-specific factors such as capital costs, feedstock type, feedstock costs, energy commodity prices, and state corporate income tax rates. Furthermore, scenario-specific costs of debt and costs of equity are employed. This paper stochastically simulates 20-year cash flows via Crystal Ball software and a discounted cash flow rate of return spreadsheet to calculate the NPV and probability of default for each location scenario.

Negative mean 20-year NPVs are calculated for seven of the eight location scenarios. A positive 20-year mean NPV of $33 million is calculated for the eighth scenario, which is also the only scenario to have a probability of a positive NPV that exceeds 50%. Very high (>98%) 10-year probabilities of default are also calculated for seven of the eight scenarios. The eighth scenario also has a probability of default that is greater than 50%, although at 61.1% it is the lowest of the eight location scenarios.

CHAPTER 5. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

5.1.   Conclusions

The revised Renewable Fuel Standard (RFS2) requires the annual blending of 16

billion gallons of cellulosic biofuel with conventional fuels by 2022. It employs two

mechanisms to ensure that this goal is met: a binding blending mandate and a blending

subsidy in the form of Renewable Identification Numbers (RIN). Despite these mechanisms,

a combination of technical, financial, and economic hurdles have prevented the cellulosic

biofuels industry from producing more than a tiny fraction of the volumes required to be

blended under the mandate to date. This underproduction has occurred despite the

publication of several studies in the refereed literature indicating that some cellulosic biofuel

pathways will be competitive with petroleum on an unsubsidized basis after

commercialization. Furthermore, a lack of investment in cellulosic biofuels capacity has

prevented researchers from accurately assessing the likely future impacts, both economic and

otherwise, of the cellulosic biofuels mandate since the identities of the feedstocks, pathways,

and locations most likely to be involved are not yet known. This dissertation develops a

framework for identifying and analyzing the likely composition of the cellulosic biofuels

industry in the future. Finally, it also uses the framework to provide a possible explanation

for why investment in cellulosic biofuels capacity has been low to date despite the presence

of the RFS2 and techno-economic analyses (TEA) suggesting that some pathways will be

competitive on an unsubsidized basis following commercialization.

The results of this dissertation indicate that few cellulosic biofuel pathways will be

economically competitive with petroleum on an unsubsidized basis. Of five cellulosic biofuel

pathways considered under 20-year price forecasts with volatility, only two (fast pyrolysis

and hydroprocessing; gasification and methanol-to-gasoline synthesis) achieve positive mean 20-year net present value (NPV) probabilities. Furthermore, recent exploitation of U.S. shale gas reserves and the subsequent fall in U.S. natural gas prices have negatively impacted the economic competitiveness of all but two of the cellulosic biofuel pathways considered; only two of the five pathways (fast pyrolysis and hydroprocessing; gasification and acetic acid synthesis) achieve substantially higher 20-year NPVs under a post-shale gas economic scenario relative to a pre-shale gas scenario.

The economic competitiveness of cellulosic biofuel pathways with petroleum is reduced further when considered under price uncertainty in combination with realistic financial assumptions. While many cellulosic biofuel TEAs in the refereed literature assume the same cost of capital (10% cost of equity and no debt financing), this dissertation employs financial analysis tools to calculate pathway-specific costs of capital for five cellulosic biofuel pathway scenarios. The analysis finds that most of the pathways incur a 14.3% cost of equity and an 18.7% cost of debt based on their cash flow volatility, both of which are substantially higher than the costs commonly assumed in the literature. Employment of these costs of capital in a comparative TEA greatly reduces the mean 20-year NPVs for each pathway while increasing their 10-year probabilities of default. Default probabilities in excess of 80% are calculated for all five scenarios analyzed on U.S. Gulf Coast and unsubsidized bases under national energy commodity prices.

Finally, this dissertation finds that the use of a U.S. Gulf Coast basis and national energy commodity prices may result in the overestimation of the economic competitiveness of cellulosic biofuel pathways. The economic competitiveness of six cellulosic biofuel pathways currently being commercialized in eight different U.S. states is quantified under

price uncertainty, utilization of pathway-specific costs of capital, and region-specific economic factors. 10-year probabilities of default in excess of 60% are calculated for all eight location scenarios considered, with default probabilities in excess of 98% calculated for seven of the eight. Furthermore, negative mean 20-year NPVs are calculated for seven of the eight location scenarios, with only one scenario (gasification and methanol-to-gasoline synthesis in Louisiana) generating a positive mean 20-year NPV at $33 million.

5.2.   Recommendations for Future Work

This dissertation develops a framework of methodologies for quantifying the economic competitiveness of multiple cellulosic biofuel pathways under price volatility, price uncertainty, scenario-specific costs of capital, and regional factors. Its presentation of both the methodologies employed as well as the results generated permits its continued application as the cellulosic biofuel industry grows and evolves, both in the U.S. and worldwide. The majority of the cellulosic biofuel TEAs currently found in the literature utilizes generic financial assumptions across different pathways and presents the economic competitiveness results as a single number, the implication being that this result is known with complete certainty. Furthermore, those TEAs that do include uncertainty analysis via Monte Carlo simulation frequently employ default probability distributions for the economic variables rather than distributions developed from historical prices. Finally, most TEAs calculate facility capital costs on a U.S. Gulf Coast basis by default and utilize national energy commodity prices to calculate cash flows. The methodologies presented in this dissertation increase the accuracy of cellulosic biofuel TEA results by employing more realistic cost assumptions and factors.

An important aspect of cellulosic biofuel TEAs that is not considered by this dissertation is processing uncertainty. Feedstock yields, process yields, and product yields are all important drivers of a pathway's economic competitiveness. All three are also uncertain, especially for pathways that have yet to begin or are undergoing the early stages of commercialization. In order for the yield uncertainty analysis to be accurate, however, the probability distributions should be based on experimental values. At present experimental yields are commonly reported in triplicate form, which is an insufficient number of data points for the development of probability distributions. The generation of a larger number of yield data points for an individual pathway would permit the inclusion of feedstock and pathway yields in the uncertainty analysis methodology presented in this dissertation, further increasing the accuracy and value of the economic competitiveness assessments.

The regional framework presented in Chapter 4 could be further expanded by consideration of region-specific differences in consumer acceptance to biofuels in general and different biofuel types in particular. For example, Midwestern consumers are more willing to purchase fuels containing higher blends of ethanol than are their counterparts near the East and West Coasts. Similarly, consumers might be willing to pay a premium for cellulosic hydrocarbon-based fuels that they are not willing to pay for cellulosic ethanol, and this premium could vary by region. Consumer acceptance of ethanol will be an important factor in the future composition of the cellulosic biofuel industry due to the existence of the ethanol blend wall. Furthermore, whether consumers require a discount or are willing to pay a premium for one fuel type relative to another will affect the economic competitiveness of cellulosic biofuel pathways. Further research into the consumer acceptance of cellulosic

biofuels would further increase the accuracy and value of results generated via the methodology presented in this dissertation.

The methodology presented in this dissertation can also be employed to conduct further analysis into the likely economic, environmental, ecological, and socioeconomic impacts of the RFS2's cellulosic biofuels mandate. At present the likely economic costs of the cellulosic biofuels mandate are unknown due to a lack of commercialization to date. Furthermore, TEAs of cellulosic biofuel pathways in the literature overestimate certainty and frequently employ arbitrary assumptions, preventing comparisons with other pathway TEAs. As such, the identities, costs, and economic competitiveness of the pathways most likely to be employed remain unknown, preventing efforts to calculate the subsidies under the RFS2 that will be necessary for the industry to succeed. Furthermore, in the initial years of commercial-scale production the RFS2 is intended to incentivize all of the pathways generating cellulosic biofuels by the amount necessary to make the least-competitive pathway competitive with petroleum. A calculated RIN subsidy value can therefore be utilized within the framework to calculate the economic competitiveness of the pathways on a subsidized basis.

Similarly, the lack of information regarding which of the available pathways are most likely to be competitive and therefore productive in the near-term also prevents accurate assessments of the mandate's environmental, ecological, and socioeconomic impacts. As discussed in Chapter 1, these impacts vary by pathway: the impacts of a cellulosic biofuel industry that is dominated by the conversion of stover to cellulosic ethanol via enzymatic hydrolysis will be different from an industry comprised of multiple pathways utilizing mixed feedstocks to produce both ethanol and hydrocarbon-based biofuels. By providing a

methodology for the identification of the feedstock, pathway, and location combinations that are most likely to be economically competitive in the U.S., this dissertation enables more accurate analyses of the mandate's potential impacts.

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